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REGULATIONS
PREAMBLES
1977–1981

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D. C. 20426

E2.18/2:

Regulations Preambles

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45 F.R. 23684 (4/8/80)	30,141
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46 F.R. 20669 (4/7/81)	30,244
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46 F.R. 33025 (6/26/81)	30,274
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46 F.R. 36692 (7/15/81)	30,262
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46 F.R. 51381 (10/20/81)	30,302	46 F.R. 58292 (12/1/81)	30,314
46 F.R. 53651 (10/30/81)	30,303	46 F.R. 58293 (12/1/81)	30,315
46 F.R. 53653 (10/30/81)	30,304	46 F.R. 58294 (12/1/81)	30,316
46 F.R. 55245 (11/9/81)	30,305	46 F.R. 58294 (12/1/81)	30,317
46 F.R. 55252 (11/9/81)	30,306	46 F.R. 58295 (12/1/81)	30,318
46 F.R. 55253 (11/9/81)	30,307	46 F.R. 60193 (12/9/81)	30,319
46 F.R. 55926 (11/13/81)	30,308	46 F.R. 60429 (12/10/81)	30,320
46 F.R. 55944 (11/13/81)	30,309	46 F.R. 60813 (12/14/81)	30,321
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46 F.R. 57467 (11/24/81)	30,312		

Index to Commission Orders

This index contains a listing of Commission orders appearing in this volume, cited by docket and paragraph number. Part I of the index lists each order in numerical sequence. Part II of the index lists each rulemaking docket in chronological and numerical sequence. Some order numbers are followed by letters in parentheses. (R) indicates an order on rehearing; (RD) an order denying rehearing; (RG) an order granting rehearing; (C) a clarifying order; and (A) an amending order.

PART I: Commission Orders by Number

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526-D	RM74-16	30,014
526-E	RM74-16	30,024
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2	RM75-25	30,006
2A	RM75-25	30,303
3	RM78-5	30,007
4	RM79-8	30,070
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6	RM77-21	30,009A
7	RM78-13	30,010
8	RM78-15	30,012
9	RM78-20	30,017
10-B	RM78-23	30,036
10-C	RM78-23	30,148
10-D	RM78-23	30,276
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12	RM78-24	30,019
13	R-406	30,020A
13-A	R-406	30,025
14	RM78-10	30,021
15	RM79-4	30,022
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16	RM79-1	30,023
18	RM79-7	30,027
19	RM79-8	30,028
20	RM79-9	30,029
20-A	RM79-9	30,037
21	RM79-12	30,032
23	RM79-22	30,040
23-A	RM79-22	30,058
23-B	RM79-22	30,065
24	RM79-32	30,044
24-A	RM79-32	30,108
24-B	RM79-32	30,137
25	RM79-31	30,046
26	RM79-33	30,047
27	RM79-18	30,049
29	RM79-15	30,053
29-A	RM79-15	30,063
29-B	RM79-15	30,067
29-C	RM79-15	30,092
30	RM79-34	30,054
30-A	RM79-34	30,084
30-B	RM79-34	30,161
30-F	RM79-34	30,263
31-A	RM79-12; RM79-19	30,090; 30,110
31-A (R)	RM79-12	30,112
32	RM78-16	30,061
33	RM79-3	30,059
34	RM79-3	30,060
34 (R)	RM79-3	30,133
36	RM79-53	30,062
37	RM79-10	30,066
38	RM79-59	30,068
38-B	RM79-59	30,126
38-C	RM79-59	30,144
39	RM79-61	30,069
40	RM79-8	30,070
41	RM79-62	30,077
42	RM79-68	30,074
42-A	RM79-68	30,109
43	RM79-72	30,078
43-A	RM79-72	30,105
44	RM79-73	30,079
45	RM79-12; RM79-19	30,080; 30,090; 30,110
45 (R)	RM79-19	30,112
46	RM79-75	30,081

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Commission Orders by Number

Order No.	Docket No.	Pur. (¶)
46 (R)	RM79-75	30,104
47	RM77-22	30,083
47-A	RM77-22	30,099
47-B	RM77-22	30,121
47-C	RM77-22	30,121
47-A (C)	RM77-22	30,121
48	RM79-6	30,087
48-A	RM79-6	30,119
48-B	RM79-6	30,186
49	RM79-14	30,085
49-A	RM79-14	30,114
49-A (A)	RM79-14	30,124
50	RM798-21	30,086
51	RM79-21	30,086A
52	RM80-1	30,088
53	RM79-38	30,093
54	RM79-23	30,091
55	RM79-40	30,096
55-B	RM79-40	30,181
56	RM79-37	30,098
56	RM79-43	30,098
56-A	RM79-37	30,115
56-A	RM79-43	30,115
58	RM80-7	30,101
59	RM79-36	30,106
60	RM79-14	30,107
61	RM79-25	30,111
63	RM79-24	30,118
64	RM80-19	30,116
64 (RD)	RM80-19	30,132
65	RM80-15	30,122
65-A	RM80-15	30,131
66	RM79-3	30,123
67	RM80-9	30,120
68	RM80-14	30,125
68A	RM80-14	30,209
69	RM79-55	30,128
69 (RGD)	RM79-55	30,160
70 (RGD)	RM79-54	30,160
70-A	RM79-54	30,159
70-B	RM79-54	30,176
70-D	RM79-54	30,234
70-E	RM79-54	30,274
71	RM80-43	30,136
72	RM80-44	30,135
73	RM80-45	30,142
74	RM80-17	30,138
76	RM79-35	30,146
77	RM80-51	30,145
78	RM79-44	30,147
79	RM80-2	30,150
81	RM79-21	30,156
82	RM80-26	30,152
83	RM80-29	30,158
84	RM79-29	30,153
85	RM80-24	30,154
85-A	RM80-24	30,163
85-B (R)	RM80-24	30,171

Order No.	Docket No.	Par. (¶)
86	RM80-16	30,155
86-A (RGD)	RM80-16	30,189
87	RM80-61	30,164
88	RM80-20	30,167
89	RM80-63	30,165
90	RM80-57	30,169
91	RM79-64	30,170
92	RM80-11	30,173
93	RM80-33	30,172
94	RM80-47	30,178
95	RM80-8	30,179
96	RM79-48	30,175
97	RM80-68	30,180
98	RM80-6	30,177
99	RM79-76	30,183
99-A	RM79-6	30,198
100	RM80-71	30,185
101	RM80-59	30,187
102	RM80-6	30,194
	RM80-7	30,194
103	RM79-47	30,200
104	RM80-62	30,201
105	RM79-76	30,199
106	RM80-65	30,204
106-A	RM80-65	30,306
107	RM80-50	30,210
108	RM80-21	30,205
109	RM79-76	30,206
110	RM79-76	30,207
111	RM79-76	30,208
112	RM81-5	30,211
113	RM80-46	30,213
114	RM80-48	30,215
115	RM79-76	30,217
116	RM79-76	30,216
117	RM79-76	30,219
118	RM79-76	30,218
119	RM81-8	30,226
120	RM81-1	30,220
121	RM80-56	30,222
122	RM80-31	30,225
123	RM81-11	30,224
124	RM79-76	30,228
125	RM79-76	30,227
126	RM79-76	30,229
127	RM79-76	30,230
128	RM79-76	30,233
129	RM79-76	30,232
131	RM80-54	30,236
132	RM81-14	30,238
133	RM79-76	30,237
134	RM80-78	30,242
135	RM81-2	30,241
139	RM79-3	30,246
140	RM81-26	30,248
141	RM79-76	30,252
142	RM79-76	30,250

Order No.	Docket No.	Par. (¶)
143	RM79-76	30,251
145	RM79-15	30,255
146	RM81-3	30,256
147	RM81-20	30,259
148	RM79-76	30,258
149	RM81-31	30,257
150	RM79-76	30,262
151	RM79-76	30,261
152	RM79-76	30,260
153	RM79-76	30,267
154	RM79-76	30,268
155	RM79-76	30,266
156	RM79-76	30,264
157	RM79-76	30,265
158	RM79-76	30,270
159	RM79-76	30,269
160	RM79-76	30,272
161	RM79-76	30,271
162	RM79-76	30,273
163	RM79-3	30,275
164	RM79-76	30,279
165	RM79-76	30,280
167	RM81-27	30,282
168	RM80-69	30,284
169	RM79-76	30,291
170	RM79-76	30,290
171	RM79-76	30,291
172	RM79-76	30,289
173	RM79-76	30,288
174	RM79-76	30,287
175	RM79-76	30,286
176	RM81-44	30,294
177	RM80-18	30,297
178	RM79-76	30,296
179	RM81-36	30,295
180	RM79-76	30,301
181	RM81-28	30,300
182	RM81-18	30,298
183	RM81-15	30,305
184	RM80-39	30,308
185	RM81-10	30,309
186	RM81-6	30,312
187	RM81-25	30,311
188	RM79-73	30,310
189	RM81-17	30,313
191	RM79-76	30,318
194	RM78-23; RM81-31	30,314
196	RM81-16	30,320
197	RM79-76	30,322
198	RM79-76	30,323
199	RM79-76	30,324

PART II: Rulemaking Dockets

Docket No.	Order No.	Par. (¶)
R406	13	30,020A
	13-A	30,025
R424		30,254
R441	455-C	30,011
		30,020
R446		30,254
R472	531-D	30,013
RM74-16	526-B	30,003
		30,004
	526-C	30,008
	526-D	30,014
	526-E	30,024
RM75-25		30,005
	2	30,006
	2-A	30,303
RM76-10		30,168
RM76-15		30,168
		30,247
RM77-6	558-G	30,001
RM77-17	5	30,009B
RM77-21	6	30,009A
RM77-22	47	30,083
	47-A	30,099
	47-A(C)	30,121
	47-C	30,121
RM78-1	1	30,002
RM78-5	3	30,007
RM78-9	11	30,017A
RM78-10	14	30,021
RM78-13	7	30,010
RM78-15	8	30,012
RM78-16	32	30,061
RM78-19		30,016
		30,043
RM78-20	9	30,017
RM78-23		30,030
	10-B	30,036
	10-C	30,148
	10-D	30,276
	194	30,314
		30,283
RM78-24	12	30,019
RM79-1	16	30,023
	RM79-3	30,026
		30,033
		30,041
		30,056
	33	30,059
	34	30,060
	66	30,123
		30,129
		30,133
		30,143
		30,162
	139	30,246
	163	30,275
RM79-4		30,033
	15	30,022
	15-A	30,031
RM7		30,057
	48	30,087
	48-A	30,119
	48-B	30,186
	99-A	30,198
RM79-7	18	30,027
RM79-8	4	30,070
	19	30,028
	40	30,070
RM79-9	20	30,029
	20-A	30,037
RM79-10		30,034
	37	30,066
RM79-11		30,039
RM79-12	21	30,032
	31-A; 45	30,110
	31-A(R)	30,112
RM79-13		30,038
RM79-14	49	30,085
	49-A	30,114
	49-A(A)	30,124
		30,242
RM79-15	29	30,053
	29-A	30,063
	29-B	30,067
		30,075
	29-C	30,092
		30,166
	145	30,255
RM79-18	27	30,049
RM79-19	45	30,080
	31-A; 45	30,090
		30,110
	45 (R)	30,112
RM79-20		30,035
RM79-21	50	30,086
	51	30,086A
		30,117
	81	30,156
		30,239
RM79-22	23	30,040
		30,052
	23-A	30,058
	23-B	30,065
		30,073
		30,089
RM79-23	54	30,091
RM79-24	63	30,118
RM79-25	61	30,111
	2-A	30,303
RM79-26		30,045
RM79-29	84	30,153
RM79-30		30,042
RM79-31	25	30,046
RM79-32	24	30,044
	24-A	30,108

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Docket No.	Order No.	Par. (¶)
	24-B	30,137
RM79-33	26	30,047
RM79-34	30	30,054
	30-A	30,084
	30-B	30,161
		30,184
		30,188
		30,192
	30-F	30,263
RM79-35	76	30,146
RM79-36	59	30,106
RM79-37	56	30,098
	56-A	30,115
RM79-38	53	30,093
RM79-40	55	30,096
RM79-43	55-B	30,181
		30,055
	56	30,098
	56-A	30,115
RM79-44		30,094
	78	30,147
RM79-47	103	30,200
RM79-48		30,190
	96	30,175
RM79-52		30,064
		30,071
		30,095
		30,141
		30,253
RM79-53	36	30,062
		30,151
RM79-54		30,100
		30,134
	70 (RGD)	30,160
	70-A	30,159
	70-B	30,176
	70-D	30,234
	70-E	30,274
		30,193
RM79-55	69	30,128
	69 (RGD)	30,160
RM79-59	38	30,068
	38-B	30,126
	38-C	30,144
RM79-60		30,076
RM79-61	39	30,069
RM79-62	41	30,077
RM79-64	91	30,170
RM79-65		30,072
RM79-66		30,103
RM79-68	42	30,074
	42-A (R)	30,109
RM79-72	43	30,078
	43-A	30,105
RM79-73	44	30,079
		30,102
	188	30,310
RM79-74	60	30,107

Docket No.	Order No.	Par. (¶)
RM79-75	46	30,081
	46 (R)	30,104
RM79-76		30,130
		30,235
		30,237
		30,243
		30,244
		30,245
		30,277
		30,278
		30,279
		30,315
		30,316
		30,317
	99	30,183
	105	30,199
	109	30,206
	110	30,207
	111	30,208
	115	30,217
	116	30,216
	117	30,219
	118	30,218
	124	30,228
	125	30,227
	126	30,229
	127	30,230
	128	30,233
	129	30,232
	133	30,237
	141	30,252
	142	30,250
	143	30,251
	148	30,258
	150	30,262
	151	30,261
	152	30,260
	153	30,267
	154	30,268
	155	30,266
	156	30,264
	157	30,265
	158	30,270
	159	30,269
	160	30,272
	161	30,271
	162	30,273
	164	30,279
	165	30,278
	169	30,292
	170	30,290
	171	30,291
	172	30,289
	173	30,288
	174	30,287
	175	30,286
	176	30,294
	178	30,296

Docket No.	Order No.	Par. (¶)
	180	30,301
	191	30,318
	195	30,319
	197	30,322
	198	30,323
	199	30,324
RM79-78		30,082
RM80-1	52	30,088
RM80-2	79	30,150
RM80-3		30,097
RM80-6	98	30,177
	102	30,194
RM80-7	58	30,101
	102	30,194
RM80-8	95	30,179
RM80-9	67	30,120
		30,140
RM80-10		30,157
RM80-10		30,182
RM80-11	92	30,173
RM80-14	68	30,125
		30,209
	68A	30,209
RM80-15	65	30,122
	65-A	30,131
RM80-16		30,113
	86	30,155
	86-A (RGD)	30,189
RM80-17	74	30,138
RM80-18		30,297
		30,307
RM80-19	64	30,116
	64 (RD)	30,132
RM80-20	88	30,167
RM80-21	108	30,205
RM80-23		30,127
RM80-24	85	30,154
	85-A	30,163
	85-B	30,171
RM80-26	82	30,152
RM80-29	83	30,158
		30,214
RM80-31	122	30,225
RM80-33	93	30,172
		30,302
RM80-39	184	30,308
RM80-42		30,254
RM80-43	71	30,136
RM80-44	72	30,135
RM80-45	73	30,142
RM80-46		30,139
	113	30,213
RM80-47	94	30,178
RM80-48	114	30,215
RM80-50	107	30,210

Docket No.	Order No.	Par. (¶)
RM80-51	77	30,145
RM80-53		30,149
		30,174
		30,202
		30,231
		30,249
		30,281
		30,304
RM80-54	131	30,236
RM80-56	121	30,222
RM80-57	90	30,169
RM80-59	101	30,187
RM80-61	87	30,164
RM80-62	104	30,201
		30,240
	106-A	30,306
RM80-63		30,197
	89	30,165
RM80-65	106	30,204
RM80-68	97	30,180
RM80-69	168	30,284
RM80-71	100	30,185
RM80-75		30,195
RM80-78		30,191
	134	30,242
RM81-1		30,196
RM81-2	120	30,220
	135	30,241
RM81-3	146	30,256
RM81-5	112	30,211
RM81-6		30,212
	186	30,312
RM81-8	119	30,226
RM81-9		30,221
RM81-10	185	30,309
RM81-11	123	30,224
RM81-12		30,223
RM81-14	132	30,238
RM81-15	183	30,305
RM81-16	196	30,320
RM81-17	189	30,313
RM81-18	182	30,298
RM81-20	147	30,259
RM81-25	187	30,311
RM81-26	140	30,248
RM81-27	167	30,282
		30,293
RM81-28	181	30,300
RM81-31	149	30,257
RM81-36	179	30,295
RM81-37		30,280
	194	30,314
RM81-41		30,299
RM81-44		30,294
RM82-6		30,321

Regulations Preambles

42 Federal Register (1977)

[¶ 30,001]

42 F. R. 53599 (October 3, 1977)

SUBCHAPTER B—REGULATIONS UNDER THE NATURAL GAS ACT

[Docket No. RM77-6; Order No. 558-G]

PART 2—STATEMENT OF PROCEDURE PRESCRIBED FOR THE IMPLEMENTATION OF THE ALASKA NATURAL GAS TRANSPORTATION ACT OF 1976, 15 U.S.C. 719, ET SEQ.

Order

AGENCY: Federal Power Commission.

ACTION: Final rule.

SUMMARY: This order amends the Commission's regulations implementing the Alaska Natural Gas Transportation Act of 1976. The Commission is required to submit a Report to the Congress commenting upon the President's selection. The Report is due twenty days after the President's transmittal. This order provides for designation of a group to prepare the Commission's Report. It also provides that designated members are not bound by certain ex parte restrictions imposed previously.

EFFECTIVE DATE: September 23, 1977.

FOR FURTHER INFORMATION CONTACT:

Brian J. Heisler, Office of the General Counsel, 202-275-4286.

SUPPLEMENTARY INFORMATION:

Order Prescribing Further Procedures and Amending Section 2.100 of the Commission's General Policy and Interpretations

Pursuant to Section 16 of the Natural Gas Act (52 Stat. 830, 15 U.S.C. 717o) and Sections 3, 5 and 8 of the Alaska Natural Gas Transportation Act of 1976 (90 Stat. 2904, et seq., 15 U.S.C. 719c), the Commission is hereby amending § 2.100 of its General Policy and Interpretations (18 CFR 2.100) to prescribe procedures for preparation of a report to the Congress commenting upon the President's decision which is scheduled for September 1, 1977. In preparation of its Report the Commission is directed to submit its comment within 20 days of the President's transmittal and to include any information with regard to the President's decision which the Commission considers appropriate. This order expands the procedural schedule set out in Order No. 558, issued December 14, 1976, which culminated in the Recommendation to the President issued May 1, 1977.

In order to permit preparation of this report to the Congress in the 20 days allotted, it will be necessary to utilize all Commission employees without regard to their previous roles in the development of the record. In this regard an exception must be provided to the procedures previously adopted in Paragraph (e) of § 2.100, Part 2, Subchapter A, Chapter I, Title 18 of the Code of Federal Regulations, which presently provides as follows:

> **§ 2.100 Statement of procedures prescribed for the implementation of the Alaska Natural Gas Transportation Act of 1976, 15 U.S.C. 719, et seq.**
>
> * * * * *
>
> (e) The ex parte rule of the Commission, as set forth in 18 CFR 1.4(c), shall not apply hereunder except that the Commission or a delegate shall not receive communications regarding matters of substance from any of the following persons:
>
> (1) Any applicant, or affiliate thereof, or any witness for an applicant;
>
> (2) Counsel for any applicant or party to the proceeding; and
>
> (3) Any party or any witness for such party, if such person has advocated on the record the approval or rejection of any project proposed by any applicant.
>
> The restrictions in this subsection shall not apply to written communications for presentation of or analysis of supplemental information or data that are filed or received pursuant to the terms of Order 558-C.

The restrictions imposed in this section were designed in part to insure impartiality in the process through which the exceptions of the parties were considered and to allow a continued advocacy role for the Staff members who participated as a party throughout the hearings and in the oral argument. The consideration of the exceptions raised by the parties was concluded by the Recommendation to the President issued May 1, 1977,[1] and Staff's advocacy role was completed in oral argument. The rationale of subsection (e) with respect to Staff communication thus no longer applies and should not remain in effect for the comment prepared pursuant to this order. Of course, the Commission in evaluating materials presented by Staff members will be cognizant of any position previously taken by such person.

The Commission finds: (1) It is necessary and appropriate in carrying out the provisions of the Alaska Natural Gas Transportation Act of 1976 that § 2.100 of the Commission's General Policy and Interpretations be amended to provide for preparation of a report commenting on the President's decision as provided herein.

(2) In view of the purpose, intent and effect of the amendment, good cause exists for making it effective upon receipt of the report from the President.

The Commission, acting pursuant to the provisions of the Alaska Natural Gas Transportation Act of 1976, (90 Stat. 830, 15 U.S.C. 719 et seq.) particularly Sections 3, 5 and 8 thereof, and pursuant to the Natural Gas Act, particularly Section 16 thereof (52 Stat. 830, 15 U.S.C. 717o) orders:

Section 2.100, Part 2, Subchapter A, Chapter I, Title 18 of the Code of Federal Regulations is amended by adding a new paragraph (f) to read as follows:

§ 2.100 Statement of procedures prescribed for the implementation of the Alaska Natural Gas Transportation Act of 1976, 15 U.S.C. 719 et seq.

* * * * *

(f) Notwithstanding the provisions of paragraph (d) of this section, the Chairman shall designate by letter persons to assist the Commission in preparation of its report to the Congress commenting upon the President's decision. Ex parte restrictions imposed by paragraphs (d) and (e) of this section shall not apply to communications from such persons to the Commission in concerning this report.

By the Commission.

KENNETH F. PLUMB,
Secretary.

[FR Doc.77-29008 Filed 9-30-77;8:45 am]

[¶ 30,002]

42 F. R. 55450 (October 17, 1977)

SUBCHAPTER A—GENERAL RULES

[Docket No. RM78-1]

PART 0—FUNCTIONS, POWERS, AND DUTIES OF THE FEDERAL ENERGY REGULATORY COMMISSION

Order Providing for Continuation of Functions Vested in, or Delegated to, the Federal Energy Regulatory Commission

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Commission issued an order providing for the continuation of the functions, powers and duties vested in the Commission by the Department of Energy Act or delegated to the Commission by the Secretary of Energy. The order states that under the Act rules and regulations relating to functions transferred to the Commission shall continue in effect until modified by the Commission. The rules adopted provide for the transfer of proceedings, set forth filing addresses and procedures, and adopt delegations of authority.

EFFECTIVE DATE: October 1, 1977.

FOR FURTHER INFORMATION CONTACT:

Kenneth F. Plumb, Secretary 202-275-4166

The Federal Energy Regulatory Commission (Commission) was established by the Department of Energy Organization Act (Act), which was enacted on August 4, 1977. (Pub. L. No. 95-91, 91 Stat. 565). The effective date of the provisions of the Act was prescribed as October 1, 1977, by Executive Order No. 12009, signed by the President on September 13, 1977. (42 FR 46267, September 15, 1977). The Act created the Federal Energy Regulatory Commission as a five-member independent regulatory commission within the Department of Energy.

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[1] We rejected El Paso Alaska Company's petition for reconsideration on June 10, 1977.

The authority and jurisdiction of the Commission is set forth in Sections 401, 402, 403, 404, 406, 407, 503 and 504 of the Act. These functions are listed in Appendix A below. The Secretary of Energy, on October 1, 1977, delegated and assigned to the Commission certain powers, authorities and responsibilities as set forth in Appendix B below.

The purpose of this order is to provide for the continuation of the functions, powers, and duties vested in the Commission by the Act or delegated to the Commission by the Secretary of Energy. The Savings Provisions in section 705(a) of the Act provide, among other things, that rules and regulations relating to functions transferred to the Commission shall continue in effect until modified by the Commission.

Insofar as the rules and regulations in Chapter I, Title 18 of the Code of Federal Regulations, apply to functions vested in, or delegated to, the Commission, such rules and regulations shall continue to apply to the functions of the Commission, except as noted below.

The rules and regulations in Title 49 CFR §§ 1241.61 and 1241.62, and Parts 1002, 1100, 1108, 1204, 1220, 1224, 1260–1262, 1300, 1330 and 1331, relating to functions under the Interstate Commerce Act which are vested in, or delegated to, the Commission, shall continue in effect until modified by the Commission.

Other matters which are delegated or assigned to the Commission by the Secretary of Energy or which are required under the Act to be referred to the Commission shall be governed by existing regulations applicable to those matters or such additional regulations as the Commission determines are necessary.

Section 705(b)(2) of the Act authorizes the Secretary of Energy and the Commission to promulgate regulations providing for the orderly transfer of proceedings pending at the time the Act takes effect. Those regulations were the subject of a separate rulemaking issued jointly by the Commission and the Secretary of Energy on October 1, 1977.

The Commission finds: (1) The amendments prescribed herein concern matters of agency organization and procedure which do not require notice or hearing under 5 U.S.C. 553.

(2) In view of the purpose, intent, and effect of the amendments herein ordered, good cause exists for making them effective October 1, 1977.

The Commission, acting pursuant to the provisions of the Department of Energy Organization Act, particularly Title IV and sections 503, 504 and 705 (91 Stat. 565), orders:

(A) The title of Chapter I of Title 18, Code of Federal Regulations is changed to "Federal Energy Regulatory Commission". In Title 18, the terms "FPC" and "Federal Power Commission" shall be deemed to refer to the Federal Energy Regulatory Commission unless the reference is to a function not vested in, delegated or assigned to the Commission.

(B) A new Part 0 is added to Chapter I, Title 18 of the Code of Federal Regulations, to read as follows:

Sec.
0.1 Purpose.
0.2 Definitions.
0.3 Transfer of proceedings.
0.4 Mailing and filing addresses.
0.5 Delegations of authority.

AUTHORITY.—Secs. 401, 402, 403, 404, 503, 504, 705, Pub. L. 95–91, 91 Stat. 582, 583, 585, 586, 590, 606.

§ 0.1 Purpose.

The purpose of this part is to provide for the continued exercise of the functions, powers, and duties vested in the Federal Energy Regulatory Commission by the Department of Energy Organization Act, or delegated to the Commission by the Secretary of Energy.

§ 0.2 Definitions.

(a) The "Commission" means the Federal Energy Regulatory Commission.

(b) "DOE Act" or "the Act" mean the Department of Energy Organization Act.

§ 0.3 Transfer of proceedings.

(a) Pursuant to the authorization provided in section 705(b)(2), and the provisions of section 705(b)(1) of the Act, all proceedings and applications pending at the time the Act takes effect, before any department, agency, commission, or component thereof, the functions of which have been transferred to the Commission by the Act, have been transferred in accordance with the joint regulations issued by the Commission and the Secretary of Energy on October 1, 1977.

(b) Pursuant to section 705(e) of the Act, the Commission authorizes the Solicitor of the Commission to file the appropriate pleadings to substitute the Commission for the Interstate Commerce Commission or the Federal Power Commission as necessary in any pending court litigation, responsibility for which is transferred to the Commission.

§ 0.4 Mailing and filing addresses.

(a) The Commission's offices are located at 825 North Capitol Street NE., Washington, D.C. 20426.

(b) The address for filings to be made with the Secretary of the Commission is: Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street N.E., Washington, D.C. 20426.

(c) Filings in all proceedings transferred from the Federal Power Commission to the Federal Energy Regulatory Commission shall be made with the Secretary of the Federal Energy Regulatory Commission under the Rules of Practice and Procedure, 18 CFR Part 1.

(d) Filings in all proceedings transferred from the Interstate Commerce Commission shall be made with the Secretary of the Federal Energy Regulatory Commission under the Interstate Commerce Commission's Rules of Practice and Procedure, 49 CFR Part 1100.

(e) Filings in all proceedings under the Commission's jurisdiction respecting appeals of remedial orders under section 503 of the Act, which proceedings are initiated by a notice of probable violation issued after October 1, 1977, shall be made with the Secretary of the Commission.

(f) Filings in all proceedings relating to the denial of a request for adjustment issued after October 1, 1977, as provided under Commission jurisdiction in section 504 of the Act, shall be made with the Secretary of the Commission.

(g) Any other filings required to be made with the Commission shall be made with the Secretary of the Commission under the Rules of Practice and Procedure, 18 CFR Part 1.

(h) All persons or jurisdictional entities required to file periodic or other reports with any agency or commission whose functions are transferred under the Act to the Commission shall file such reports which relate to those transferred functions with the Secretary of the Commission. The Commission hereby affirms, adopts and continues in effect all previously-approved forms for making periodic or other reports.

(i) Hand-delivered documents to be filed with the Secretary of the Commission shall be submitted to Room 2110, 825 North Capitol Street NE., Washington, D.C. 20426. Documents received after regular business hours (8:30 a.m. to 5 p.m.) are deemed filed on the next regular business day.

§ 0.5 Delegations of authority.

The respective delegations of authority contained in § 3.5 of Title 18, Code of Federal Regulations, to the Secretary, Chief Accountant, Regional Engineers, the Chief Administrative Law Judge and the designated presiding administrative law judges of the Federal Power Commission and any other delegation of authority contained in Title 18, Code of Federal Regulations are hereby reaffirmed as delegations to the officials succeeding to those positions in the Federal Energy Regulatory Commission, to the extent that such delegations concern functions which are now vested in the Commission by the DOE Act or are delegated, transferred or assigned to the Commission by the Secretary of Energy.

(C) The amendments adopted herein shall be effective October 1, 1977.

(D) The Secretary shall cause prompt publication of this order to be made in the FEDERAL REGISTER.

By the Commission.

KENNETH F. PLUMB,
Secretary.

APPENDIX A—FUNCTIONS OF THE FEDERAL ENERGY REGULATORY COMMISSION

1. The investigation, issuance, transfer, renewal, revocation, and enforcement of licenses and permits for construction, operation, and maintenance of dams, water conduits, reservoirs, powerhouses, transmission lines, or other works for the development and improvement of navigation and for the development and utilization of power across, along, from, or in navigable waters under Part I of the Federal Power Act;

2. The establishment, review, and enforcement of rates and charges for the transmission or sale of electric energy, including determinations on construction work in progress, under Part II of the Federal Power Act, and the interconnection, under section 202(b), of such Act, of facilities for the generation, transmission, and sale of electric energy (other than emergency interconnection);

3. The establishment, review, and enforcement of rates and charges for the transportation and sale of natural gas by a producer or gatherer or by a natural gas pipeline or natural gas company under sections 1, 4, 5, and 6 of the Natural Gas Act;

4. The issuance of a certificate of public convenience and necessity, including abandonment of facilities or services, and the establishment of physical connections under section 7 of the Natural Gas Act;

5. The establishment, review, and enforcement of curtailments, other than the establishment and review of priorities for such curtailments, under the Natural Gas Act;

6. The regulation of mergers and securities acquisitions under the Federal Power Act and the Natural Gas Act;

7. The authority to exercise any power under (a) sections 4, 301, 302, 306 through 309, and 312 through 316 of the Federal Power Act, and (b) sections 8, 9, 13 through 17, 20, and 21 of the Natural Gas Act to the extent the Commission determines such power to be necessary to the exercise of any function within its jurisdiction;

8. The establishment of rates or charges for the transportation of oil by pipeline or the establishment of the valuation of any such pipeline, under the Interstate Commerce Act (49 U.S.C. 1, et seq.), as amended, and the Trans-Alaska Pipeline Authorization Act (Pub. L. 93-135):

9. The jurisdiction to consider any proposal by the Secretary of Energy to amend any regulation required to be issued under Section 4(a) of the Emergency Petroleum Allocation Act of 1973 which is required by Section 8 or 12 of such Act to be transmitted by the President to, and reviewed by, each House of Congress, under section 551 of the Energy Policy and Conservation Act, except in the event that the President determines that an emergency situation of overriding national importance exists, as provided in section 402 (c)(2) of the DOE Act;

10. The jurisdiction to hear and determine any matter arising under any function of the Secretary of Energy involving any agency determination required by law to be, or which the Secretary determines shall be, made on the record after an opportunity for agency hearing, except for those functions of the Secretary under Section 105 and 106 of the Energy Policy and Conservation Act and except for the authority of the Secretary to regulate the exports and imports of natural gas or electricity unless the Secretary assigns such a function to FERC;

11. The authority to prescribe rules, regulations, and statements of policy of general applicability with respect to any function under the jurisdiction of FERC pursuant to Section 402 of the DOE Act;

12. The authority to prescribe such procedural and administrative rules as necessary to the exercise of its functions;

13. The powers authorized by the law under which the FERC's functions are exercised to hold hearings, sign and issue subpoenas, administer oaths, examine witnesses, and receive evidence;

14. The authority to consider and take final action on any rules, regulations, and statements of policy of general applicability respecting any function within the jurisdiction of FERC under section 402 of the DOE Act proposed by the Secretary pursuant to section 403(a) of the DOE Act;

15. The consideration of any rule, regulation, or statement of policy of general applicability proposed by the Secretary of Energy in the exercise of any function transferred to the Secretary by section 301 or 306 of the DOE Act, for the purpose of providing an opportunity for public comment on such rule, regulation, or statement of policy should the Commission determine that the proposed action may significantly affect any function within the jurisdiction of the Commission and issuance of a recommendation on the proposed action to the Secretary;

16. The jurisdiction to review remedial orders issued by the Secretary, when the person receiving the order has notified the Secretary he intends to contest such order, and to issue and order, based upon findings of fact, affirming, modifying, or vacating the remedial order, or directing other appropriate relief; and the authority, upon receipt of notice from the Secretary that the remedial order will be contested, to stay the effect of the remedial order unless FERC finds that the public interest requires immediate compliance with such remedial order; and

17. The jurisdiction to review and to issue such orders as may be necessary or appropriate with respect to a denial of a request for adjustment under section 504(a) of the DOE Act.

Appendix B—Delegations and Assignments to the Federal Energy Regulatory Commission from the Secretary of Energy

1. Part I of the Federal Power Act (Pub. L. 280, 66th Cong., 2d Sess.), to the extent that such authority is not transferred to, and vested in, FERC by Section 402(a)(1)(A) of the DOE Act: *Provided*, That this paragraph does not delegate functions under (i) Section 4(a) of the Federal Power Act as it relates to river basin appraisals and (ii) Section 24 of the Federal Power Act as it relates to the disposition of power site lands;

2. Section 203 of the Federal Power Act (relating to the disposition, merger or consolidation of facilities and the acquisition of securities);

3. Section 204 of the Federal Power Act (relating to the issuance of securities and the assumption of liabilities);

4. Section 206(b) of the Federal Power Act (relating to the investigation and determination of the cost of production or transmission of electric energy), as FERC determines appropriate to perform its vested or delegated functions;

5. Section 207 of the Federal Power Act (relating to adequate and sufficient interstate service);

6. Section 209 of the Federal Power Act (relating to use of boards composed of State representatives and cooperation with State commissions);

7. Section 304 of the Federal Power Act (relating to annual and periodic or special reports), as FERC determines appropriate to perform its vested or delegated functions;

8. Section 305 of the Federal Power Act (relating to officers or directors benefiting from the sale of issued securities and to interlocking directorates);

9. Section 311 of the Federal Power Act (relating to investigations regarding the generation, transmission, distribution, and sale of electric energy), as FERC determines appropriate to perform its vested or delegated functions;

10. Sections 1(b) and 1(c) of the Natural Gas Act (Pub. L. 688, 75th Cong., 3d Sess.) (relating to certain exemptions from the provisions of the Natural Gas Act);

11. Section 3 of the Natural Gas Act with respect to the decision of pending cases assigned to FERC by rule;

12. Section 5(b) of the Natural Gas Act (relating to the investigation and determination of the cost of production or transportation of natural gas), as FERC determines appropriate to perform its vested or delegated functions;

13. Section 10 of the Natural Gas Act (relating to annual and periodic or special reports), as FERC determines appropriate to perform its vested or delegated functions;

14. Section 12 of the Natural Gas Act (relating to officers or directors benefiting from the sale of issued securities);

15. Section 19 of the Natural Gas Act (relating to rehearing on orders);

16. The Interstate Commerce Act (49 U.S.C. 1, et seq.) and other statutes which formerly vested authority in the Interstate Commerce Commission or the chairman and members thereof, as such statutes relate to the transportation of oil by pipeline, to the extent that such statutes are not transferred to, and vested in, FERC by Section 402(b) of the DOE Act: *Provided*, That this paragraph does not include any of the authority under Section 11 of the Clayton Act (15 U.S.C. 21);

17. To issue orders, and take such other action as may be necessary and appropriate, to direct the Energy Information Administration to gather energy information pursuant to the Federal Energy Administration Act of 1974 or the Energy Supply and Environmental Coordination Act of 1974 to the extent necessary or appropriate to the exercise of regulatory functions vested in or delegated to the Federal Energy Regulatory Commission; and

18. The authority to take such other action as the Secretary or his authorized delegates may, from time to time, authorize.

Except as provided in Paragraph 11, this Order does not include the authority to carry out the functions delegated herein to the extent such functions are vested in the Secretary pursuant to his authority to regulate the exports or imports of natural gas or electricity, under Section 402(f) of the DOE Act: *Provided*, That the Secretary may from time to time delegate to FERC such other authority under Section 3 of the Natural Gas Act as may be determined appropriate.

The authority delegated to FERC may be further delegated, in whole or in part, as may be appropriate.

FERC shall consult with the Administrator of the Energy Information Administration ("EIA") with respect to the exercise of functions under paragraphs 4, 7, 9, 12, 13, and 17, as EIA considers appropriate.

All actions pursuant to any authority delegated by this Order taken prior to and in effect on the date of this Order are hereby confirmed and ratified, and shall remain in full force and effect as if taken under this Order, unless or until rescinded, amended or superseded.

This Order is effective October 1, 1977.

[FR Doc.77-30155 Filed 10-14-77;8:45 am]

[¶ 30,002A]

42 F. R. 55637 (10/18/77)

Delegations and Assignments of Certain Matters by the Secretary of Energy

AGENCY: Department of Energy.

ACTION: Notice.

SUMMARY: Notice is hereby given of delegations and assignments of certain matters by the Secretary of Energy (Secretary) to the Federal Energy Regulatory Commission, in accordance with Sections 642 and 402(e) of the Department of Energy Organization Act, 91 Stat. 565 (1977).

EFFECTIVE DATE: October 1, 1977.

FOR FURTHER INFORMATION CONTACT:

Nancy E. Williams, Department of Energy, Office of General Counsel, Washington, D. C. 20545, 202-566-2454.

SUPPLEMENTARY INFORMATION: The Department of Energy (DOE) was established by the Department of Energy Organization Act (the "Act"), which was made effective October 1, 1977, by Executive Order 12009, dated September 13, 1977 (42 FR 46267, September 15, 1977). The Act consolidated in DOE various energy functions previously performed by several federal agencies, so that federal energy policy and programs may be effectively coordinated and administered. The Act transfers to, and vests in, DOE and the independent collegial body within DOE, the Federal Energy Regulatory Commission, the functions of the former Federal Energy Administration, the Energy Research and Development Administration, the Federal Power Commission (FPC), and certain functions previously performed by the Interstate Commerce Commission (ICC), the Department of the Interior, the Department of Housing and Urban Development, the Department of the Navy, the Department of Commerce, and the Naval Reactor and Military Application Programs established under the Atomic Energy Act of 1954.

Sections 401-407, 503, and 504 set forth the jurisdiction and authorities of the Federal Energy Regulatory Commission (the "Commission"). These sections describe those functions previously performed by the FPC and the ICC that are transferred to, and vested in, the Commission by the Act. These sections also describe the role of the Commission in DOE rulemaking proceedings, its role with respect to appeals of Remedial Orders issued by the Secretary, and its role with respect to denials of adjustments issued by the Secretary.

In addition to jurisdiction over the functions transferred to, and vested in, the Commission by the Act, Section 402(e) provides that the Commission will have jurisdiction over other matters that the Secretary may assign to it, after public notice is given of such assignment:

> In addition to the other provisions of this section, the Commission shall have jurisdiction over any other matter which the Secretary may assign to the Commission after public notice * * *.

Section 642 of the Act gives the Secretary a general power of delegation:

> Except as otherwise expressly prohibited by law, and except as otherwise provided in this Act, the Secretary may delegate any of his functions to such officers and employees of the Department as he may designate, and may authorize such successive redelegations of such functions within the Department as he may deem to be necessary or appropriate.

Pursuant to these provisions of the Act, public notice is hereby given that the Secretary delegates as of October 1, 1977, and assigns, effective upon publication of this notice, to the Commission, the authority to carry out several functions which by the Act are transferred to, and vested in, the Secretary. The assignment is in the form of a delegation, in accordance with all delegations of authority made by the Secretary. The delegation is set forth below in its entirety. Pursuant to this delegation, the Commission will henceforth have authority to perform the functions under the authorities statutory listed.

Pursuant to the delegation, the Commission may exercise its authority with respect to functions relating to the collection of data via reports or other means only after appropriate consultation with the Administrator of the Energy Information Administration (EIA) within DOE. Such consultation will insure coordination between the Commission and EIA so that a central, comprehensive, and unified energy data and information program is maintained to the greatest extent possible within DOE.

The delegation also contains a restricted delegation by the Secretary of his authority to regulate the exports or imports of natural gas under Section 3 of the Natural Gas Act. This limited delegation is to provide the Commission the authority to retain jurisdiction over several pending import cases up until the time of the timely filing of all briefs on and opposing exceptions to the initial decision of the presiding Administrative Law Judge in each case. These cases are transferred to the Commission for proceedings consistent with the joint rule issued October 1, 1977, by the Secretary and the Commission.

(Department of Energy Organization Act, Pub. L. 95-91; EO 12009, 42 FR 46267).

Issued in Washington, D. C., on October 6, 1977.

[¶ 30,003]

42 F. R. 58737 (November 11, 1977)

SUBCHAPTER G—APPROVED FORMS, NATURAL GAS ACT

[Order No. 526-B; Docket No. RM74-16]

PART 3—ORGANIZATION: OPERATION; INFORMATION AND REQUESTS

Order on Court Remand Prescribing FPC Form No. 40 With Amendments; Correction

JUNE 30, 1977.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Erratum Notice.

SUMMARY: The Commission is correcting Ordering Clause (B) of Order No. 526-B, issued June 30, 1977, published July 29, 1977 (42 FR 38556), as follows: Asterisks should be inserted under paragraph (a) of § 3.170, and the designation of paragraph "(b)" should be changed to "(31)".

FOR FURTHER INFORMATION CONTACT:

Kenneth F. Plumb, Secretary, 202-275-4166.

KENNETH F. PLUMB,
Secretary.

[FR Doc.77-32799 Filed 11-10-77;8:45 am]

[¶ 30,004]

42 F. R. 58737 (November 11, 1977)

[Docket No. RM74-16]

PART 260—STATEMENTS AND REPORTS (SCHEDULES)

Natural Gas Companies' Annual Report of Proved Domestic Gas Reserves: Form No. 40

AGENCY: Federal Energy Regulatory Commission.

ACTION: Extension of Time.

SUMMARY: The Federal Energy Regulatory Commission is extending the time to and including December 1, 1977, for filing Form No. 40, as required by Commission Order No. 526-B. This action is taken in response to numerous requests for extensions of time and as a result of eight applications for rehearing and a motion for partial stay of Order No. 526-B. The extension of time will allow the Federal Energy Regulatory Commission adequate time to act on the merits of the applications for rehearing and motion for stay.

DATES: Form No. 40 must be filed on or before December 1, 1977.

ADDRESSES: Form No. 40 should be filed with the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

Kenneth F. Plumb, Secretary, 202-275-4166.

SUPPLEMENTARY INFORMATION: Requests for extensions of time in which to file Form No. 40, as required by Commission Order No. 526-B, issued June 30, 1977, published July 29, 1977 (42 FR 38556), were filed by the following: Suburban Propane Gas Corp. (filed July 29, 1977); McMoRan Exploration Co. (filed September 12, 1977); Jake L. Hamon (filed September 23, 1977); 1975 McCormick Oil & Gas Program (filed September 26, 1977); General American Oil Co. of Texas (filed September 30, 1977); Getty Oil Co. (filed October 4, 1977); Consolidate Oil & Gas Co., Inc. (filed October 5, 1977); Cities Service Co. (filed October 7, 1977); W. R. Grace & Co. (filed October 7, 1977); Amerada Hess Corp. (filed October 11, 1977); Husky Oil Co. (filed October 11, 1977); Exchange Oil & Gas Corp. (filed October 11, 1977); Supron Energy Corp. (filed October 13, 1977); and Atlantic Richfield Co. (filed October 14, 1977).

On October 7, 1977, 1975 McCormick Oil & Gas Program filed a petition to review the Commission's September 30, 1977, letter order which denied McCormick's September 26, 1977, request for extension of time.

On October 1, 1977, pursuant to the provisions of the Department of Energy Organization Act (DOE Act), Pub. L. 95-91, 95 Stat. 565 (August 4, 1977), and Executive Order No. 12009, 42 FR 46267 (September 13, 1977), the Federal Power Commission ceased to exist and its principal functions and regulatory responsibilities were transferred to the Federal Energy Regulatory Commission (FERC), which was activated on October 1, 1977. The "savings provisions" of Section 705 (b) of the DOE Act provide that proceedings pending before the FPC on the date the DOE Act takes effect shall not be affected and that orders shall be issued in such proceedings as if the DOE

Act had not been enacted. The joint regulation adopted on October 1, 1977, by the Secretary of Energy and the FERC provided that this proceeding would be continued before the FERC.

KENNETH F. PLUMB,
Secretary.

[FR Doc.77-32798 Filed 11-10-77;8:45 am]

[¶ 30,004A]

42 F. R. 61491 (December 5, 1977)

DELEGATION AND ASSIGNMENT OF FUNCTIONS UNDER THE ALASKA NATURAL GAS TRANSPORTATION ACT OF 1976 BY THE SECRETARY OF ENERGY TO THE FEDERAL ENERGY REGULATORY COMMISSION

AGENCY: Department of Energy.

ACTION: Notice.

SUMMARY: Notice is hereby given of the delegation and assignment by the Secretary of Energy to the Federal Energy Regulatory Commission of functions under the Alaska Natural Gas Transportation Act of 1976 which, but for the enactment of the Department of Energy (DOE), Organization Act, would have been within the authority of the Federal Power Commission.

EFFECTIVE DATE: December 5, 1977.

FOR FURTHER INFORMATION CONTACT:

Nancy E. Williams, Department of Energy, Office of General Counsel, 12th and Pennsylvania Avenue NW., Room 7132, Washington, D. C. 20461, 202-566-2454.

Robert L. Baum, Deputy General Counsel, Federal Energy Regulatory Commission, Washington, D. C. 20426, 202-275-4333.

SUPPLEMENTARY INFORMATION: The Department of Energy (DOE), was established by the DOE Organization Act, Pub. L. 95-91, 42 U. S. C. 7101, et seq. (1977) (the Act), which was enacted on August 4, 1977. The effective date of the Act was prescribed as October 1, 1977, by Executive Order 12009, dated September 13, 1977 (42 FR 46267, September 15, 1977).

Sections 401-407, 503 and 504 of the Act set forth the jurisdiction and authorities of the Federal Energy Regulatory Commission (the Commission), the independent collegial body within DOE. These sections describe those functions previously performed by the Federal Power Commission and the Interstate Commerce Commission that are transferred to, and vested in, the Commission by the Act. These sections also describe the role of the Commission in DOE rulemaking proceedings, its role with respect to appeals of certain Remedial Orders issued by the Secretary, and its role with respect to denials of adjustments to certain rules, regulations, and orders issued by the Secretary.

In addition to jurisdiction over the functions transferred to, and vested in, the Commission by the Act, Section 402(e) provides that the Commission will have jurisdiction over other matters that the Secretary may assign to it, after public notice is given of such assignment:

> In addition to the other provisions of this section, the Commission shall have jurisdiction over any other matter which the Secretary may assign to the Commission after public notice * * *.

Section 642 of the Act gives the Secretary a general power of delegation:

> Except as otherwise expressly prohibited by law, and except as otherwise provided in this Act, the Secretary may delegate any of his functions to such officers and employees of the Department as he may designate, and may authorize such successive redelegations of such functions within the Department as he may deem to be necessary or appropriate.

Pursuant to these provisions of the Act, public notice is hereby given that the Secretary delegates and assigns to the Commission the authority to carry out certain functions which by the Act are transferred to, and vested in, the Secretary. The assignment is in the form of a delegation, in accordance with all delegations of authority made by the Secretary.

The delegation gives to the Commission the authority to transmit to the Congress the report on the Presidential decision regarding a transportation system for delivery of Alaska natural gas which is required by Section 8(f) of the Alaska Natural Gas Transportation Act of 1976 (Pub. L. 94-586, 15 U. S. C. 719). The delegation also gives to the Commission the authority to perform any function which, but for the enactment of the DOE Act, the Federal Power Commission could have performed with regard to any approved transportation system, as defined by Section 4 of the Alaska Natural Gas Transportation Act of 1976, including the execution of certificates and other ministerial steps. The latter delegation is an assignment of authority to the extent such authority was not transferred to and vested in the Commission by Section 402(a) of the DOE Act, or has not otherwise been transferred, assigned, or delegated to the Commission pursuant to the Act.

(Department of Energy Organization Act, Pub. L. 95-91; E. O. 12009, 42 FR 46267)

Issued in Washington, D. C. on November 28, 1977.

[¶ 30,004B]

42 F. R. 63810 (December 20, 1977)

FEDERAL ENERGY REGULATORY COMMISSION RELATING TO APPLICATION BY DISTRIGAS OF MASSACHUSETTS CORP. FOR A TEMPORARY CERTIFICATE TO CONSTRUCT NATURAL GAS IMPORT FACILITIES

Delegation and Assignment of Functions

AGENCY: Department of Energy.

ACTION: Notice.

SUMMARY: Notice is hereby given of the delegation and assignment by the Secretary of Energy to the Federal Energy Regulatory Commission of the authority to carry out functions vested in the Secretary under the Department of Energy (DOE) Organization Act as those functions relate solely to a request by Distrigas of Massachusetts Corp. for a temporary certificate to construct certain facilities involved in the importation of natural gas.

EFFECTIVE DATE: December 20, 1977.

FOR FURTHER INFORMATION CONTACT:

Nancy E. Williams, Department of Energy, Office of General Counsel, 12th and Pennsylvania Avenue NW., Room 7132, Washington, D. C. 20461, 202-566-2454.

Robert L. Baum, Deputy General Counsel, Federal Energy Regulatory Commission, Washington, D. C. 20426, 202-275-4333.

SUPPLEMENTARY INFORMATION: The Department of Energy (DOE) was established by the DOE Organization Act, Pub. L. 95-91, 42 U. S. C. 7101, et seq. (1977) (the Act), which was enacted on August 4, 1977. The effective date of the Act was prescribed as October 1, 1977 by Executive Order 12009, dated September 13, 1977 (42 FR 46267, September 15, 1977).

Sections 401-407, 503, and 504 of the Act set forth the jurisdiction and authorities of the Federal Energy Regulatory Commission (the Commission), the independent collegial body within DOE. These sections describe those functions previously performed by the Federal Power Commission and the Interstate Commerce Commission that are transferred to, and vested in, the Commission by the Act. These sections also describe the role of the Commission in DOE rulemaking proceedings, its role with respect to appeals of certain Remedial Orders issued by the Secretary, and its role with respect to denials of adjustments to certain rules, regulations, and orders issued by the Secretary.

In addition to jurisdiction over the functions transferred to, and vested in, the Commission by the Act, section 402(e) provides that the Commission will have jurisdiction over other matters that the Secretary may assign to it, after public notice is given of such assignment:

In addition to the other provisions of this section, the Commission shall have jurisdiction over any other matter which the Secretary may assign to the Commission after public notice * * *.

Section 642 of the Act gives the Secretary a general power of delegation:

Except as otherwise expressly prohibited by law, and except as otherwise provided in this Act, the Secretary may delegate any of his functions to such officers and employees of the Department as he may designate, and may authorize such successive redelegations of such functions within the Department as he may deem to be necessary or appropriate.

Pursuant to these provisions of the Act, public notice is hereby given that the Secretary delegates and assigns to the Commission the authority to carry out certain functions which by the Act are transferred to, and vested in, the Secretary. The assignment is in the form of a delegation, in accordance with all delegations of authority made by the Secretary.

The delegation gives to the Commission the authority to carry out such functions as are vested in the Secretary to regulate natural gas imports under sections 301 and 402(f) of the DOE Act with respect to Distrigas of Massachusetts Corp., Docket No. CP77-216, solely as the authority relates to the request filed July 18, 1977 by Distrigas of Massachusetts Corp. for issuance of a temporary certificate under section 7 of the Natural Gas Act to construct certain facilities at its Everett, Mass., liquefied natural gas marine terminal.

(Department of Energy Organization Act of Pub. L. 95-91; E. O. 12009, 42 FR 46267.)

Issued in Washington, D. C., on December 13, 1977.

Regulations Preambles

43 Federal Register (1978)

[¶ 30,004C]

43 F. R. 997 (January 5, 1978)

Amendment of Delegation Order No. 0204-1 From the Secretary of Energy

AGENCY: Department of Energy.

ACTION: Notice.

SUMMARY: Notice is hereby given of the amendment of Delegation Order No. 0204-1 of the Department of Energy, which was a delegation and assignment of certain matters by the Secretary of Energy to the Federal Energy Regulatory Commission. The amendment delegates and assigns to the Commission functions under sections 4 and 24 of the Federal Power Act, which the Secretary had reserved to himself in Delegation Order No. 0204-1.

EFFECTIVE DATE: December 23, 1977.

FOR FURTHER INFORMATION CONTACT:

Nancy E. Williams, Department of Energy, Office of General Counsel, 12th and Pennsylvania Avenue NW., Room 7132, Washington, D.C. 20461 202-566-2454.

Robert L. Baum, Deputy General Counsel, Federal Energy Regulatory Commission, Washington, D.C. 20426, 202-275-4333.

SUPPLEMENTARY INFORMATION: The Department of Energy (DOE) was established by the DOE Organization Act, Pub. L. 95-91, 42 U.S.C. 7101, et seq. (1977) (the Act), which was enacted on August 4, 1977. The effective date of the Act was prescribed as October 1, 1977, by Executive Order 12009, dated September 13, 1977 (42 FR 46267, September 15, 1977).

Sections 401-407, 503 and 504 of the Act set forth the jurisdiction and authorities of the Federal Energy Regulatory Commission (the Commission), the independent regulatory commission within DOE. These sections describe those functions previously performed by the Federal Power Commission and the Interstate Commerce Commission that are transferred to, and vested in, the Commission by the Act. These sections also describe the role of the Commission in DOE Rulemaking proceedings, its role with respect to appeals of certain Remedial Orders issued by the Secretary, and its role with respect to denials of adjustments to certain rules, regulations, and orders issued by the Secretary.

In addition, section 402(e) of the Act provides that the Commission will have jurisdiction over any other matter assigned to it by the Secretary, upon public notice being given of the assignment:

> In addition to the other provisions of this section, the Commission shall have jurisdiction over any other matter which the Secretary may assign to the Commission after public notice. * * *

Section 642 of the Act gives the Secretary a general power of delegation:

> Except as otherwise expressly prohibited by law, and except as otherwise provided in this act, the Secretary may delegate any of his functions to such officers and employees of the Department as he may designate, and may authorize such successive redelegations of such functions within the Department as he may deem to be necessary or appropriate.

Pursuant to the above provisions, public notice is hereby given that the Secretary delegates and assigns to the Commission the authority to carry out certain functions which by the act are transferred to, and vested in, the Secretary. The assignment is in the form of a delegation, in accordance with all delegations of authority made by the Secretary.

The delegation order set forth below amends Delegation Order No. 0204-1 by abrogating the reservation of sections 4(a) and 24 of the Federal Power Act contained in paragraph 1 of that Order. The amendment of the Delegation Order with respect to section 4(a) amends the original paragraph 1 to the extent it reserved "Section 4(a) of the Federal Power Act as it relates to river basin appraisals", since it has become apparent, subsequent to execution of the original Delegation Order, that the Commission may have need to gather data for river basin appraisals in order to carry out its responsibility to assess whether or not a project considered for hydroelectric licensing is best adapted to comprehensive development of the waterway on which the project would be located. The determination of adaptability must be made by the Commission pursuant to section 10(a) of the Federal Power Act. The amendment makes clear that the authority vested in the Commission pursuant to the Delegation Order is co-extensive with its authority under the DOE Act, in particular section 402(a) (2) of the act, which provides:

> The Commission may exercise any power under the following sections to the extent the Commission determines such power to be necessary to the exercise of any function within the jurisdiction of the Commission:
>
> (A) Sections 4, 301, 302, 306 through 309, and 312 through 316 of the Federal Power Act. * * *

By the amendment, the Commission is given authority to exercise any power under section 4 of the Federal Power Act to the extent the Commission determines utilization of the power is necessary for the Commission to perform the functions assigned to it by the Delegation Order.

The abrogation of the reservation of section 24 as it was included in the original Delegation order is a delegation and assignment only for a period of 6 months. The authority is delegated because section 24 applications do relate to hydroelectric licensing functions carried out by the Commission. Furthermore, the Commission presently has an efficient method of handling section 24 applications, and the applications are of a type which must be acted upon rapidly and daily. For these reasons, it is believed to be in the public interest to have the Commission continue to process section 24 applications for a period of 6 months. During this time period, the Commission will provide the Assistant Secretary for Resource Applications with a copy of each section 24 application filed with it, and afford the Assistant Secretary a reasonable time period to comment on the application. At the end of the 6-month time period, the Commission will prepare a report for the Secretary on its activities of those 6 months with respect to the section 24 applications. At that time, a decision will be made as to which entity or officer of the Department should from henceforth have responsibility for the section 24 applications.

(Department of Energy Organization Act, Pub. L. 95-91; E.O. 12009, 42 FR 46267.)

Issued in Washington, D.C. on December 29, 1977.

[¶ 30,005]

43 F. R. 5362 (February 8, 1978)

[Docket No. RM75-25]

PART 2—GENERAL POLICY AND INTERPRETATIONS

Amendments to Policy Regarding Certification of Pipeline Transportation Agreements

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: On June 24, 1977, the Federal Power Comission[1] issued a notice of its intent to review the policy set forth in Order No. 533 and 533-A (10 CFR 2.79) with respect to the transportation by jurisdictional pipelines of natural gas from the onshore domain and the offshore non-Federal domain to non-resale industrial and commercial customers for high priority uses. The purpose of the policy was to provide high priority users with a means to mitigate the effects of curtailments by purchasing supplemental gas supplies directly from producers.

At its inception, that policy was regarded as experimental in nature and as requiring a subsequent review based on experience with the program to determine if it should be continued. The June 24 notice therefore requested comments on whether the policy should be continued and on whether it should be modified in certain respects.

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[1] On October 1, 1977, jurisdiction over this proceeding was transferred to the Federal Energy Regulatory Commission pursuant to the Department of Energy Organization Act, Pub. L. 95-91.

Upon review of the comments, staff reports and experience with the program, the Federal Energy Regulatory Commission has determined that the policy set forth in Order No. 533 and 533-A has been of assistance to high priority users, and that since the conditions which led to its adoption persist, it should be continued. The Commission has also adopted a number of minor modifications to the policy as explained in detail below.

EFFECTIVE DATE: February 1, 1978.

FOR FURTHER INFORMATION CONTACT:

Frederick Cornelius, Office of Producer and Pipeline Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, Washington, D.C. 20426, 202-275-4496.

Jane Drennan, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, Washington, D.C. 20426, 202-275-4252.

I. PROCEDURAL BACKGROUND

On October 1, 1977, pursuant to the provisions of the Department of Energy Organization Act (DOE Act), Pub. L. 95-91, 91 Stat. 565 (August 4, 1977) the Executive Order No. 12009, 42 FR 46267 (September 15, 1977), the Federal Power Commission ceased to exist and its functions and regulatory responsibilities were transferred to the Secretary and the Federal Energy Regulatory Commission (FERC) which, as an independent commission within the Department of Energy, was activated on October 1, 1977.

The "savings provisions" of section 705(b) of the DOE Act provide that proceedings pending before the FPC on the date the DOE Act takes effect shall not be affected and that orders shall be issued in such proceedings as if the DOE Act had not been enacted. All such proceedings shall be continued and further actions shall be taken by the appropriate component of DOE now responsible for the function under the DOE Act and regulations promulgated thereunder. The functions which are the subject of these proceedings were specifically transferred to the FERC by Section 402(a) (1) or (2) of the DOE Act.

The joint regulation adopted on October 1, 1977, by the Secretary and the FERC entitled "Transfer of Proceedings to the Secretary of Energy and the FERC", 10 CFR ——: *Provided*, That this proceeding would be continued before the FERC. The FERC takes action in this proceeding in accordance with the above mentioned authorities.

By notice issued June 24, 1977, and published at 42 FR 34521, July 6, 1977, the Federal Power Commission stated its intent to review the policy statement of Order Nos. 533 and 533-A. At its inception, the policy statement was viewed as experimental in nature, and recognizing that requests for renewal of previously issued authorizations under Order No. 533 would be filed this winter, the Commission concluded that it was appropriate to consider whether the policy should be continued, and if so, on what basis. Although the Commission set forth issues which it considered to be of primary importance, it also invited any interested person to raise any issue or suggestions believed to be helpful to its inquiry.

In Order No. 533, the Commission adopted as § 2.79 of its General Policy and Interpretations, 18 CFR Part 2, a statement of policy with respect to the transportation by jurisdictional pipelines of natural gas sold by certain producers from the onshore domain and the offshore non-Federal domain to non-resale industrial and commercial customers for high priority uses. Due to the steady increase in curtailment levels on interstate pipelines which resulted in production cutbacks, plant closing, employee layoffs, and shortages of various products and services, the Commission found it appropriate to issue the statement of policy with regard to specific pipeline transportation arrangements so that industrials requiring gas for high priority use could obtain an independent source of gas for their operations. The policy was viewed as a vehicle for obtaining required gas supplies for high priority use due to the anticipated severe curtailment on the interstate pipelines during the 1975-1976 winter.

The Commission projected that this policy would increase the amount of gas available to the interstate market, thereby resulting in utilization of idle pipeline capacity with attendant cost benefits to pipelines and their customers. There was also perceived a potential for increased producer revenues, which would then promote increased exploration and development of gas supplies. In adopting this policy statement, the Commission stated:

> The policy is admittedly experimental and requires empirical evidence on its merits in specific applications and trial before we can determine whether the public convenience and necessity demand that the policy be made permanent. (Citations omitted.) If, upon review, it appears that the policy has not resulted in the attraction of incremental gas supplies to meet the demand of the interstate market and to avert an imminent crisis in the winter of 1975-1976, we will revise of abandon the experiment.[8]

In response to the notice of intent to review the program, an overwhelming majority of the parties filed comments in support of the policy's continuation asserting that the gas transported under Order No. 533 represented a crucial part of the energy supply for many industrial users requiring gaseous fuel for process, plant protection and other direct-fired applications in their manufacturing facilities. The parties supporting the program also maintained that it has reduced the adverse impact of the severe natural gas shortage on the United States' economy. Many comments detail the benefits to specific commercial and industrial establishments which otherwise could not have continued production or maintained their labor forces.

In its initial comments, the Commission Staff described the operation of the policy. As the 1975-1976 winter was considerably warmer than normal, only 28 arrangements were filed with the Commission during the heating season. As of May 1976, only 365,183 Mcf had been transported under the program, or an average seasonal daily volume of slightly more than 2,000 Mcf. From May 1, 1976, through December 31, 1976, 35 arrangements were filed; however, with the onset of the severe winter, a dramatic increase in applications occurred.

As of June 1977, a total of 106 separate arrangements have been filed pursuant to this program.[3] For the period of August 1975 through March 1977, a total of 7,969,587 Mcf had been delivered of which 1,857,708 Mcf was delivered in the month of March 1977. The consumers served by eleven pipelines have purchased gas directly under this program,[4] however direct and indirect customers of Columbia Gas Transmission Corp., Transcontinental Gas Pipe Line Corp. and Texas Gas Transmission Corp. have purchased more than 75 percent of the total supply transported under this program and more than 60 percent of the March volumes thereof.[5] Of the applications filed from August 1975 to June 1977, 40 percent were filed during the emergency period.

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[8] Order No. 533, Docket No. RM75-25, 54 FPC——, mimeo p. 28 (1975).

II. POLICY CONSIDERATIONS

In its notice, the Commission set forth issues that interested parties should address. In light of the two years of actual experience with the experimental 533 program, the first question was whether the program should be continued. We have independently reviewed past transactions under Order No. 533 to ascertain the effects of this program.

A. CONTINUATION OF THE POLICY

Of the parties that filed comments, the majority were strongly in favor of continuing the 533 policy. The level of anticipated economic disruption that has been forestalled for the past two years through utilization of the 533 procedures is predicted to continue and therefore, the need for these supplemental supplies also will continue.

It is evident from our review that the program has become an important means of maintaining plant operations in facilities which use natural gas and are subject to curtailment. As of November 30, 1977, 113 certificates had been issued under this program,[6] and approximately 16 million Mcf of gas had been transported. The deliveries under this program were a critical element last winter in maintaining the operating capacity of many industries in the eastern United States. Approximately 40 percent of the certificates issued and 38 percent of the 533 deliveries occurred during last year's emergency period, from November 1, 1976, to March 31, 1977. Over 6 million Mcf of gas was delivered during the winter emergency period.[7]

These supplies were used primarily by customers in industrial states. The major states receiving the largest quantities of 533 supplies were Pennsylvania, North Carolina, and Ohio. Over 85 percent of the gas involved in these transactions was produced in the states of Louisiana, Ohio, and Texas where many marginal sources of supply are available. The following indicates the number of purchases which occurred in the consuming states:

Pennsylvania	27
South Carolina	24
Ohio	19
Tennessee	14
Indiana	13
Virginia	12
North Carolina	10
Kentucky	9
West Virginia	8
Maryland	3
New York	3
Alabama	2
Illinois	2
Iowa	2
Mississippi	2
New Jersey	1

The following table sets forth the number of applications for transportation and percentage of such which involved 533 gas from the eight produc-

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[3] Each arrangement may involve a group of purchasers, multiple delivery points and/or a number of transporters so that the actual number of certificate applications filed with the Commission is greater.

[4] This figure represents the primary pipelines who were directly responsible for the particular end-uses of supply.

[5] See Appendix I, "Notice of Proposed Rulemaking to Review Policy Statement of Order Nos. 533 and 533-A," Docket No. RM75-25, —— FPC —— (June 24, 1977).

[6] Twenty-two are currently being reviewed. One hundred and thirty five applications have been filed. See Appendix A which sets forth the number of applications certificated and the volumes delivered and consumed at plant facilities.

[7] During the winter of 1976-77, a total of 6,065,969 Mcf was delivered. The monthly deliveries were as follows:

November 1976	666,344
December 1976	654,110
January 1977	1,444,039
February 1977	1,443,768
March 1977	1,857,708
Total	6,065,969

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ing states. Nine applications to transport industrial owned gas are not included.

		Percent
Louisiana	70	56.0
Ohio	26	21.0
Texas	13	10.0
Oklahoma	7	5.0
West Virginia	6	5.0
Mississippi	2	2.0
Michigan	1	0.5
New Mexico	1	0.5
Total	126	100

The February 4, 1977, report of the Natural Gas Action Group of the Department of Commerce stated that 1.2 million workers were unemployed as a direct result of gas curtailments. The 533 supplies offset curtailment into Priority 2 which was being experienced on many major interstate systems forestalling plant shut-downs and work stoppages. Of the 92 applications filed through March 31, 1976, the 533 transactions allowed more than 215,000 workers to continue their employment. Without this program, the number of unemployed workers could have been larger.

Through this policy, many natural gas consumers, including factories, schools and hospitals, have been able to remain in operation when gas curtailments otherwise would have forced them to shut down for extended periods of time. In addition to hospitals and public schools, over 100 industrial facilities in at least 16 states have remained in operation during periods of severe gas curtailment as a result of gas obtained under Order No. 533. Without these supplies, the economic repercussions would probably have been significant. Many of the products produced by these industrial consumers are essential and any shortage resulting from plant closings could have caused a ripple effect throughout both regional economies and the nation, as a whole. The applications indicating the end uses to which the gas has been utilized are as follows:[*]

General usage	*Number of facilities*
Metals	58
Glass	34
Textiles	32
General plant usage	18
Chemicals and synthetics	17
Commercial	17
Food processing	11
Brick	5
Paper	3
Oil production	2
Agriculture	1
Coal gas	1

The 533 program in conjunction with Emergency Natural Gas Act of 1977 proved to be critical programs as they provided means of securing necessary gas supplies for facilities without alternate fuel capability and allowed industrial production and the employment of workers to continue.

In summary, the effects of the policy have been positive as economic dislocation and unemployment were minimized. Pipeline curtailments are continuing and will certainly continue for the next several years. High priority industrial users must have access to additional gas supplies or the severe economic disruptions that were prevented in the past by the 533 policy will occur.

One of the arguments that has been proffered in opposition to the 533 policy is that it may divert gas from the interstate market. Most of the parties that filed comments dispute this contention. They view these limited gas supplies as being produced from marginal reserves that otherwise would not have been developed at the national ceiling prices or would have been sold to the intrastate market for boiler fuel or other low priority use.

Several of the interstate pipelines oppose the continuation of this policy. They argue that they are placed at a competitive disadvantage in securing additional supplies.[*] While stating that deregulation is necessary, these pipelines maintain that Order No. 533 provides a method whereby a producer of new reserves may obtain a price above the national rate. They claim that the result of Order No. 533 is not to enable a prospective high priority customer to purchase gas actively sought by the intrastate market, but to allow industrial customers to obtain the same gas supplies sought by the interstate pipelines at the national rate for its system supply.

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[*] Above total end use applications will exceed total of filed applications because a few applications were filed on behalf of a number of small industries.

[*] These pipelines are Florida Gas Transmission Co., Mid-Louisiana Gas Co., Southern Natural Gas Co., Arkansas-Louisiana Gas Co., Northern Natural Gas Co., and Cities Service Gas Co.

The American Public Gas Association (APGA)[10] opposes Commission consideration of the continuation of the policy on two grounds. APGA argues that the Commission should wait for the issuance of a decision by the U.S. Court of Appeals for the District of Columbia Circuit as to the legality of Order Nos. 533 and 533-A.[11] APGA also excepts to this program on the basis that since certain interstate pipelines were curtailed into Priority 1 last winter, supplies might have been available to the interstate resale market to offset curtailment absent the alternative offered producers by Order No. 533.

After examining the certificate applications and reports filed pursuant to Order Nos. 533 and 533-A, the Bureau of Natural Gas, as part of the staff comments, concluded that there was no evidence of diversion. In its comments, Staff recommended that the current reporting requirements be expanded to elicit additional information from future applicants so as to better assess potential diversion. Staff suggested that the following factors be considered in reviewing future proposals: Location of the sale, proximity and availability to the interstate market, and the relative value of the gas. We adopt herein additional reporting requirements to obtain this information.[11a]

The assertion that the implementation of the 533 program diverts gas from pipeline supply is the most serious challenge to the 533 program. The stated purpose of the policy was to supplement available pipeline supply by making what would otherwise be intrastate gas accessible to curtailed interstate customers through direct purchase.

While a bifurcated pricing system exists (intrastate versus interstate), gas will continue to be sold intrastate for prices in excess of the Commission's national rate. The Commission recognizes that most 533 sales were made at rates in excess of the nationwide rate as shown in Appendix B.[12] It is also apparent that interstate pipelines can not compete for these supplies at that price, however, we have found no evidence that the 533 program has resulted in either an increase in intrastate prices or a deterrent to interstate dedications. So long as the intrastate market demand is greater than the supply, the prices unregulated, and the uses unrestricted, parity of access will not be restricted by Commission action; but it will be restricted instead by the dynamics of the marketplace.

In reviewing these transactions to determine whether this policy resulted in the diversion of gas from the intrastate pipeline systems, we assessed the nature of the producing properties. Staff experience indicated that most of the wells involved produced small amounts of gas. The volumes transported under those arrangements substantiated this finding. In addition, a further measure of the marginal nature of these producing properties was considered to be the number of amended applications filed. Amended applications were submitted by the transporting pipelines to allow the delivery of previously certificated volumes of gas from new sources of supply. The need for such amendments arises when the initial producing property did not deliver as projected. In the past 6 months, six applications were filed, about 15 percent of all applications filed during that period, which indicates the marginal nature of the 533 supply sources.

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[10] Although the Consumers Federation of America is named in the instant petition, only counsel for APGA signed the filing.

[11] "APGA v. FPC", No. 75-2105 (D.C.).

[11a] The Commission has determined that in certain instances the information should be provided where "available". Availability is defined for the purpose of these requirements as that information which the nonresale industrial or commercial consumer has obtained as a result of a good faith effort. All participants in Section 2.79 transactions are reminded that the Commission must base its findings on substantial evidence.

[12] See Appendix II of the June Notice, Supra, note 4.

The Commission attempted to avoid any possibility of diversion by requiring the sellers of 533 gas to certify that the gas was otherwise not available to the interstate market. Nevertheless, in order to further ensure that diversion does not occur, we will adopt the requirements suggested by Staff to assist in our continuing monitoring program.

Each applicant is required to submit data in support of the proposed price. In reviewing the proposed rate, the Commission will assess data available in Form 45, other publicly available sources and information supplied by the Applicant. Consideration will also be given to the intrastate price levels in determining whether a certificate should be issued. The Commission has sought to avoid approving applications that include a purchase price[13] which would create upward pressure on gas prices in the area of production. Our review process is intended to ensure that the level of prices in the intrastate market will be unaffected by this program. It will be the intention of the Commission to review applications with regard to price following the policy stated above.

In response to APGA's argument that a Commission determination in the 533 review should be deferred pending a decision of the appellate court as to the legality of this program, it should be sufficient to refer to our discussion herein of the exigencies of the winter period, the deepening curtailment of most pipelines and the need to avoid severe economic disruption through extensive industrial shut-down.

Upon review, we have concluded that the program should be continued. Last winter many direct industrial consumers were able to maintain plant operations solely due to the availability of these 533 supplies. In the absence of this program, severe economic disruption caused by shut-down of many industrial plants would have occurred. This conclusion is substantiated by the number of authorizations which were issued by the FPC during the first three months of 1977.

The continued need for this program has been established in the recent omnibus pipeline hearings conducted to ascertain the magnitude and potential impact projected curtailments during the 1977-78 winter heating season. By Order issued May 11, 1977,[14] the FPC instituted proceedings to review the supply situation on 29 major interstate pipelines and to provide an overview of potential curtailment impact for the forthcoming winter on both a normal and 10 percent colder than normal basis.

As a result of these hearings, the Commission concluded that if the actual weather were 10 percent colder than normal, 23 pipelines would experience no significant economic dislocations; however, six pipelines anticipated severe industrial curtailments, which would undoubtedly result in plant closings. By Order issued September 14, 1977,[15] the Commission reopened these proceedings to more thoroughly evaluate the curtailment impact on these six pipelines. In so doing, the Commission elicited information as to what self-help measures, such as implementation of Order No. 533 procedures, were under consideration. The results of these proceedings were set forth in Staff reports,[16] which we incorporate into the record herein, detailing the projected impact of the 1977-78 winter curtailment on these pipelines which clearly establish that Order No. 533 procedures should be available this winter in order to provide a means of mitigating potentially severe industrial curtailment.

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[13] The Commission has rejected certain applications where it found the rate to be excessive or has conditioned certificate authorization by limiting the term, volumes or price in order to limit the rate to an appropriate level. Transcontinental Gas Pipe Line Corp., et al., Docket Nos. CP77-427, et al., issued August 29, 1977; Natural Gas Pipeline Co. of America, et al., Docket Nos. CP77-242, et al., issued July 14, 1977; Texas Gas Transmission Corp., et al., Docket Nos. CP77-296, et al., issued May 31, 1977; Transcontinental Gas Pipe Line Corp. et al., Docket Nos. CP77-452, et al., and United Gas Pipeline Co., Docket No. CP77-428, issued January 6, 1978.

[14] Alabama-Tennessee Natural Gas Company, et al., Docket Nos. RP77-65, et al.

[15] East Tennessee Natural Gas Company, et al., Docket No. RP77-72, et al.

[16] El Paso Natural Gas Co., Docket No. RP77-74; East Tennessee Natural Gas Co., Docket No. RP77-72; Tennessee Gas Pipeline Co., Docket No. RP77-86; Tennessee

B. TERM OF THE CERTIFICATE

In Order No. 533, the certificates were limited to 2 years. The 533 program is an emergency type of measure designed to assist currently curtailed high priority users to secure supplemental gas supplies while they arrange to convert to more plentiful alternate fuels. It is not intended to be a permanent solution to these industrials' energy needs. That answer is conversion to alternate and more abundant fuels, such as coal and other fuels. Legislation to effectuate such conversions and to encourage more efficient use of natural gas is presently before Congress.

This Commission will not, through its policy pronouncements, elevate an essentially stop-gap measure to the level of a permanent palliative to the natural gas shortage for the relatively small group of industrial concerns that are in a position to take advantage of this program. We recognize, however, that conversion to alternate sources of energy is expensive, difficult, often slow and sometimes infeasible depending on the state of the technology for any particular use. We do not want to unduly disrupt industrial processes by prematurely terminating the 533 policy, a result which would defeat the very purpose for which the program was begun. Therefore, we find that the certificates should be limited to no more than a two year period to avert critical economic dislocations and maintain the Commission's flexibility to review and respond to the changing national gas supply situation.[19]

We will grant a buyer of 533 gas an extension of the existing authorization for 2 years if all qualifications are met. Any additional extension, however, will be granted only if substantial evidence establishes that conversion to an alternate fuel was infeasible during the term of the sale. In reviewing these requests on a case-by-case basis, the Commission will determine whether the industrial consumer has made a good faith effort to inquire into alternate fuel capability and conversion potential and further, that there is an insufficient period of time to develop such capability during the period of proposed use of 533 supplies. The reasons for the consumer's inability to implement alternate fuel capability should be clearly set forth in order to present adequate substantive evidence.

C. DIVERSION OF 533 GAS TO PRIORITY 1 CUSTOMERS

In its notice, the FPC requested the parties to comment on whether the Commission should condition transportation authorization for 533 supplies upon diversion to the transporting interstate pipeline when there is a threat of actual curtailment. Under such a condition, if the pipeline supply were inadequate to meet the requirements of residential, small commercial and human needs consumers in Priority 1, the pipelines would have an alternate method of coping with emergencies of limited duration.

Staff endorsed the proposed condition with certain limitations. Staff argued that if any gas were to be diverted, only those volumes over and above the amount necessary for plant protection should be made available, adequate notice should be provided in order to prevent damage to the equipment and materials being processed by the industrial consumer; and explicit assurance should be provided that the Commission will not assert jurisdiction upon the supplying producer. In addition, Staff advocated that the pipelines be required to pay back the gas diverted from industrial customers; however, in the event the customer were unable to utilize the volumes in accordance with the provisions of the policy, an exception should be created whereby the customer could take the volumes for lower priority use during the term of the authorization.

Many of the parties disagreed sharply with Staff's proposal, stating that such a condition would violate the Natural Gas Act as producers would be

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Natural Gas Lines, Inc., Docket No. RP77-87; Transcontinental Gas Pipe Line Corp., Docket No. RP77-89; United Gas Pipeline Co., Docket No. RP77-92 and Reports were issued October 14, 1977.

[19] It is implicit that this Commission may initiate review of this policy at any time. It may be appropriate for us to take such action after the enactment of the National Energy Act.

selling gas to be resold in interstate commerce at rates in excess of those permitted under the Act without a certificate of public convenience and necessity authorizing such sales. Noting that some producers now require that the gas purchase contract covering the sale of 533 supplies contain a clause providing for its automatic cancellation if the gas is resold, they argued that the proposed amendment to the policy would result in the automatic termination of many 533 contracts. Many parties also cited the Emergency Natural Gas Act of 1977 as support for their contention of the inadvisability of requiring this limited diversion.[18]

Others argued that "Priority 1 curtailment" at the pipeline level does not necessarily mean that there is actual curtailment of Priority 1 uses because the distributor customer may have supplemental supply sources in addition to pipeline supply. In order to mitigate these effects, some suggested that the emergency condition protecting Priority 1 customers adopted in Opinion No. 778[19] should be incorporated if the Commission finds that a protective condition is in the public interest.

Alternate means of protecting Priority 1 essential uses are available without Federal regulation. The distributors may defer delivery of gas to the 533 purchaser during an emergency, although the purchaser would continue to request gas at the wellhead making a supply available to the interstate pipeline. After the crisis passes, the distributor would deliver to the 533 purchaser an amount equal to that obtained during the emergency. This procedure is viewed as superior as there would be no unlawful passage of title of the 533 gas to a third party. Its viability depends upon the voluntary cooperation of the industrial consumer, distributor, pipeline. This commission cannot mandate such transactions; however, they appear desirable.

We find the arguments against our imposition of a diversion condition to be persuasive and therefore reject the Staff's suggestion. Order No. 533 sales are exempt from Commission jurisdiction because they are direct sales and not sales for resale. If the Staff proposal were adopted, diversion of the gas to resale markets would result and the character of the transportation would be legally changed since title would change and the gas would be unlawfully sold to a third party for resale. We conclude that at the present time the policy need not be modified to incorporate the proposed condition. During the severe emergency last winter, the pipelines were able to provide natural gas to essential human uses through voluntary cooperative efforts.

D. PERMITTING PRIORITY ONE CONSUMERS TO PARTICIPATE

In the initial rulemaking proceeding, the FPC rejected arguments to expand the policy to include direct sales to Priority One consumers. In Order No. 533, the Commission found that due to the "exceedingly large number of residential and small commercial customers that might try to take advantage of such a policy",[20] further study was necessary. The majority of the parties, including Staff, oppose the proposed expansion for a variety of reasons. They argue that these loads are temperature-sensitive and therefore do not require a relatively consistent gas supply. Moreover, the administrative and regulatory aspects of the proposed modification would create an unwarranted burden on the pipeline. It would be impractical for an individual household or a small commercial consumer to enter into such contracts. These arguments were previously considered during the initial rulemaking whereupon the Commission concluded that Priority One consumers should not be allowed to participate in this program. No new arguments have been raised which would form a basis for modification of that determination.

A related question is whether Order No. 533 should be modified to allow the transportation of gas purchased or developed by distribution companies. Northern Illinois Gas Co. (NI-Gas), Citizens Gas and Coke Utility (Citizens) and Michigan Gas Utilities Co. (Michigan Gas) argue that such a modification is necessary and in the public interest as it would encourage domestic drilling activity and production of additional gas supplies for consumers located outside gas producing States. Maintaining that many local distribution companies are experienced in finding gas, parties favoring this view state that these companies should be allowed to compete with intrastate purchasers and thereby divert additional gas from the intrastate market. Since some distributors operate large storage reservoirs and therefore can purchase gas which nonresale purchasers cannot economically purchase, these companies assert that they should be allowed to participate in an expanded 533 program.

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[18] By legislation, Congress created the authority to reallocate natural gas supplies under certain emergency situations; however, it specifically excluded Order No. 533 gas from such reallocation.

[19] Transcontinental Gas Pipe Line Corp., Docket No. RP72-99.

[20] Supra, note 1 at Mimeo p. 22.

These arguments are similar to those previously raised during the initial rulemaking proceedings. Upon review, the FPC determined that the proposed modification would be inadvisable since distributors would resell the supply which would be a jurisdictional activity and subject to the just and reasonable standard of sections 4 and 5 of the Natural Gas Act. For this reason, we find no basis upon which to amend the previous findings.

In a related matter, NI-Gas proposed that purchases by industrial and commercial users under this program not preempt pipeline capacity that would otherwise be available to local distributors and that all certificates issued under § 2.79 be conditioned to contain a provision subjecting that transportation to interruption where necessary to allow the pipeline capacity to be used in an emergency situation by local distributors acting under §§ 2.68 and 157.22 of the Commission's regulations. NI-Gas did not cite a single instance where the pipeline capacity on any interstate system has been preempted. In addition, one of the necessary findings in the approval of the 533 application is that there is available pipeline capacity. A concerned distributor could therefore address this issue in a specific proceeding when the proposed transportation is under consideration; however, since this problem does not appear to have actually happened, there is no basis at the present time for a general pronouncement on this point. Should the need for a condition as suggested by NI-Gas arise, the Commission will reexamine the question.

E. NEW CUSTOMERS

In the initial rulemaking, the FPC considered and rejected the application of § 2.79 to others than "existing customers" of interstate pipelines who are subject to curtailment. In its June notice, the FPC raised this point for discussion again and set forth three proposed categories for possible inclusion: (1) The transportation of direct sale gas to new customers, (2) customers not served by the interstate pipeline, and/or (3) volumes in excess of those presently being received by existing customers through jurisdictional pipeline suppliers.

Many parties favored the expansion of the policy beyond the current category of "existing customers", arguing that there is no basis to deny these customers the use of gas which would not otherwise be available to the interstate market. The Commission's Office of Policy and Analysis (now Office of Regulatory Analysis) concurred with these arguments, stating that supplies to new customers represent an addition to the flow of interstate gas which would not have been forthcoming in the absence of these customers' efforts and further that there are economic benefits from permitting the transportation. Moreover, it concluded that the gas contracted for by such customers is no more likely to be diverted from potential interstate supplies than any other gas under Order No. 533.

In their comments, the Commission's Office of the General Counsel and the Bureau of Natural Gas (now Office of Pipeline and Producer Regulation) opposed the expansion of the present policy to allow the transportation of direct sales gas under the three proposed categories. Allowing the transportation of 533 gas to new customers, such as a new fertilizer plant constructed in 1977, was seen as creating an unwarranted dependence on supplies which are authorized for a limited term. The use of 533 gas would allow users to postpone development of a reliable energy supply for two years and could require the incurrence of an unjustifiable expense in subsequent conversion of plant facilities to utilize alternate energy sources. The Office of the General Counsel and Bureau of Natural Gas believe that a better energy policy would be for such customers to utilize alternate fuels from the inception rather than requiring the conversion to such after a limited term.

We concur with this recommendation for the reasons advanced. The underlying purpose of the 533 policy is temporarily to assist existing customers mitigate the effects of curtailment pending conversion to alternate fuels. Adding new customers would be contrary to that intent. The application of the current 533 policy should not be extended to customers not presently served by the interstate pipeline as that would also be contrary to the purpose of Order No. 533. Due to the unregulated price of gas supplies in the intrastate market, customers of an intrastate pipeline are in a better position to obtain needed gas supplies than the customers of an interstate pipeline. To allow this expansion of the policy could diminish the limited potential supplies available to ultimate existing users by permitting additional competition.

In a related matter, United Gas Pipeline Co. (United) proposed that the Commission expand its policy statement to include two new classes of industrial customers: (1) Small industrial customers with requirements under 300 Mcf per day; and, (2) large industrial customers converting to alternate fuel but still lacking total alternate fuel capability. United maintained that the continued operation of these plants is essential to avoid the same type of economic dislocation with which Priority 2 and 3 consumers qualifying under the current policy statement are threatened.

As to the first category, United proposed that the small industrial with requirements of less than 300 Mcf per day should be included in the highest curtailment category available to industrial gas. United further argues that there is an apparent inconsistency in Commission policies in that these industrial requirements are often placed in the highest industrial category under Order No. 467-B type plans but remain ineligible for Order No. 533 consideration as they do not fall within the definition of plant protection, feedstock or process use. Because of economies-of-scale considerations discouraging their conversion to alternate fuels and the *de minimus* volumes involved, United asserts that there is adequate justification for expanding the policy.

Section 2.78(b) of the Commission's regulations provides for proceedings for extraordinary relief from curtailment and is the appropriate vehicle for seeking relief in the aforementioned situation. Order No. 533 would provide an alternate means to meet the projected curtailment of industrial customers, however, further consideration appears necessary prior to our adoption of the proposed modification. As to United's proposal to expand the policy to include large industrial consumers who are in the process of converting to alternate fuel, we find that it could have an adverse impact in minimizing the urgency of completing the necessary conversion. Moreover, there would be extreme difficulties administratively in distinguishing which plants made a good faith effort to effectuate such conversion on a prompt and expeditious basis resulting in an exemption to the current policy standards.

F. TRANSPORTATION OF USER OWNED GAS

In its initial policy statement, the FPC did not include the transportation of gas produced or owned by the industrial consumer; however, it did indicate that any filing requesting such authorization would be considered. In its recent notice, the Commission proposed to review the advisability of including this type of arrangement in the 533 program. Most parties, as well as the Office of Policy Analysis, supported the proposed expansion of the policy, arguing that the development of reserves in remote locations would be encouraged and supply of available gas for Priority 2 and Priority 3 uses would be augmented. It is asserted that marginal onshore reserves will not be developed unless industrial consumers are willing to make the substantial effort and investment necessary and, therefore, the expansion of the policy in this manner would not create any additional risks of diversion from the interstate market.

The supporting parties stated that continuation of the two-year limitation on the transportation certificate would effectively preclude the development of such reserves despite modification of the policy to include consumer-owned gas or reserves-in-place because the industrial consumer (investor) would not be assured of an adequate opportunity to recover the substantial investment necessary to acquire a long-term gas supply. Consequently, long-term certificates for these projects were requested by these parties.

OGC and BNG contended that development of consumer-owned supplies or the purchase of reserves-in-place are not short-term ventures and the nature of these transactions places them outside the intent of Order Nos. 533 and 533-A. Staff argued that they should be subject to a case-by-case scrutiny under section 7(c) of the Natural Gas Act.

We concur that the requested modification of the policy does not fall within the intent of Order No. 533 as it would allow much more than short-term emergency measures to maintain high priority use. The considerations implicit in such proposals should be reviewed in the context of section 7(c) as they do not conform to the criteria of Order No. 533. The transportation of consumer-owned gas or reserves-in-place for a period not exceeding two years can be construed as falling within the scope of the policy.

G. INTERMEDIARIES (BROKERS)

In its notice, the FPC sought comments referring to the role of intermediaries (brokers) that attempt to bridge the gap between the industrial consumers seeking to purchase and the producers wanting to sell natural gas supplies. These intermediaries have acted in the role of "agents" in locating supplies of 533 gas for industrial and commercial buyers and arranging transportation from the point of production to consumption. They charge a fee for the various types of services performed, such as, planning, purchasing, contracting for gathering systems, negotiating transportation agreements, and fulfilling administrative requirements. They act solely for the industrial consumer from whom they receive all their compensation. In some instances, the brokers charge their industrial customer a fee based upon the number of Mcf's of gas delivered to the facility.

The Commission is not opposed to brokering activities and we do not want to discourage the use of these important services, but the Commission is concerned about the amount of any brokerage fee and any impact it may have on the price paid by the industrial customer. Although the Commission has no direct jurisdiction over the producer price in a direct sale, in reviewing the transportation certificate application the Commission is required to examine the effect of the price paid on market forces in the area of the purchase.[31] The Commission has examined several transactions in which brokers participated[32] and has concluded that the total cost of the gas delivered to the industrial must be reviewed in determining whether the proposed transportation is in the public interest. When brokers participate, the application for certification of the transportation must include a statement as to the total fee charged, how it is computed, and any affiliation between the broker and the seller, buyer, or pipeline applicant.

H. COST OF GATHERING FACILITIES

Some of the 533 applications recently received have included a provision whereby the buyer paid for the cost of installing gathering lines between the pipeline and the source of the gas, but the producer retained title to these facilities. The inclusion of these costs increases the total price of the gas to the industrial consumer. The Commission is not opposed to the consumer paying for such facilities provided that the total cost of the delivered 533 supplies remain consistent with the market price in the producing area.[23] Accordingly, we will amend our filing requirements to ensure that the information necessary to make an informed judgment on this matter is before the Commission. Under such arrangements, the filing made with the Commission should itemize these costs incurred by the customer, ownership, date of construction and the terms of payment.

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[31] *Transcontinental Gas Pipe Line Corp. v. FPC*, 365 U.S. 1 (1961).

[32] Transcontinental Gas Pipe Line Corporation, Docket No. CP77-542, issued November 8, 1977; Transcontinental Gas Pipe Line Corporation, Docket No. CP76-423, issued November 5, 1976; and Transcontinental Gas Pipe Line Corportion, Docket No. CP77-240, issued October 26, 1977.

I. USE OF INTRASTATE PIPELINES

After reviewing past transactions under the existing policy statement, the Commission is aware that the transportation costs may be a major factor in the industrial consumer's consideration of the total costs of purchasing a particular supply. Under some arrangements that have been approved by the Commission the transportation of the supply from the producer to the consumer has required the participation of two or more interstate pipelines when intrastate pipelines might have transported the supply more efficiently and economically.

A hypothetical example is illustrative of the value of an intrastate pipeline participation in the transportation of 533 supplies. Assume a producer in the vicinity of Ward County, Tex., which is near Midland, has marginal supplies available and a high priority industrial consumer, which is a customer of Transcontinental Gas Pipe Line Corp., (Transco), needs these supplies to offset curtailment. For purposes of the hypothetical, it is assumed that the redelivery point to Transco will be at a point near Houston, Tex., where a potential intrastate pipeline company has facilities. In order to transport the available gas to the Transco system through solely interstate pipelines, the gas would go through three interstate systems prior to arrival at Transco's system at a point near Houston, Tex. The gas would be picked up by Northern Natural Gas Co. in Texas and be transported approximately 460 miles to Kansas where it would be transferred to Panhandle Eastern Pipeline Co. (Panhandle). The gas would travel 610 miles on this system where there would be a point of inter-connection with Trunkline Gas Co. which would exchange the gas with Transco by displacement in Texas. The total cost of this transportation would be approximately 35.4 cents per Mcf.[24]

If an intrastate facility in Texas with available capacity were willing to transport the gas approximately 600 miles to a point near Houston for delivery to Transco, the total cost of the transportation would be 18.0 cents.[25] The cost savings are significant. This example focuses only on transportation costs; however, the reluctance of intrastate entities to participate in 533 transactions could result also in construction of unnecessary facilities, or the abandonment of potential arrangments.

Participation by an intrastate pipeline in a 533 transaction involves it in interstate transportation which is a jurisdictional activity. In order to encourage intrastate pipelines to praticipate in 533 arrangements, the Commission will assert only a limited claim of jurisdiction over participating intrastate pipelines. commission jurisdiction will be restricted to the 533 service performed and will not serve as a basis for the assertion of authority over other activities of the intrastate pipeline nor its facilities. Should an intrastate entity choose to participate, the Commission will issue a certificate providing pregranted abandonment authorization to discontinue service upon expiration of the term.

We also find it appropriate to limit the filing requirements and waive most reporting requirements. We therefore will adopt Staff's proposals which provide two options for the intrastate entity. The intrastate pipeline may file a joint application with the interstate pipeline setting forth the proposed transportation fee and the cost basis thereof. Under this procedure, the interastate pipeline would have the primary obligation of preparing the application; however, it would incorporate the required information relating to the intrastate transaction. Both applicants would receive the appropriate certificates. In the event that the intrastate pipeline chooses not to file a joint application, the second option allows the intrastate pipeline to file a abbreviated certificate application[36] that would subject it to only limited jurisdiction arising only from the transportation transactions, with waiver of most of Section 157 filing requirements. These are procedural alternatives; the certificate issued to the intrastate pipeline would be identical under either method.

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[23] See Consolidated Gas Supply Corp. (Westinghouse) Docket No. CP77-211 (April 22, 1977) where the FPC analyzed a connection cost charged on an Mcf basis and conditioned the certificate by limiting the industrial payment to the actual cost of the facilities.

[24] Northern 460/100×14.5 cents/Mcf=20.70 cents, Panhandle 610/100×2.41 cents/Mcf=14.70 cents: Total—35.40 cents/Mcf.

[25] Intrastate 600/100×3.0 cents/Mcf=18.00 cents/Mcf.

As part of this certification procedure the Commission must approve the proposed intrastate pipeline transportation rate as just and reasonable.[37] In contrast to interstate pipelines, the Commission does not have tariffs on file which establish the appropriate transportation rate, although Section 5(b) of the Natural Gas Act provides a vehicle for obtaining such information.[38] In the event an intrastate pipeline takes advantage of our invitation to participate on a limited jurisdictional basis, it will be incumbent upon the applicant to demonstrate that the proposed rate is just and reasonable by the submission of appropriate data. Proposed transportation rates derived from rates approved by state regulatory commissions will be considered, and given some evidentiary weight when the intrastate transporter submits a statement of the proposed rates and the supporting data provided the state regulatory body.

J. TAKE OR PAY PROVISIONS

In its notice, the Commission characterized the [t]ake-or-pay provision, coupled with the limitations on the purpose for which the gas may be used, (as) possibly the most problematic issue resulting from the implementation of this program.[39]

Most of the parties agreed with the Commission's assessment and suggested that the Commission should modify the policy to allow for additional flexibility. The comments highlighted the conflict with the policy statement in that there is an attempt to attract intrastate gas to the interstate market while imposing strict limitations on its end use. We recognize that the fluctuations in an industrial customer's use of natural gas may not be conducive to the full realization of both of these objectives.

The problem arises because the producer desires a guarantee that as long as certain volumes are available for sale, the supplies will either be sold or paid for, even if not actually purchased. If the latter occurs, the price of each unit of gas obtained by the user increases. This is of concern to the Commission because of the price impact and the loss to the interstate market of supplies that have been purchased but not delivered. This situation arises because the level of curtailment fluctuates such that during the summer season many industrial users are not being curtailed and cannot use 533 gas. Also, if the winter curtailment is not deep enough to make up the difference, gas will be paid for but not taken. Consequently, some parties filing comments proposed extending the term of the certificate to permit make-up and/or easing the priority restrictions on the use of 533 gas.

One method of dealing with this problem was suggested by the Staff, which proposed that the policy should be amended to establish a general rule that the underlying sales contract should not include a take-or-pay provision that exceeds 80 percent on an annual basis. In the event that the take-or-pay provision is 100 percent, a limit of 75 percent should be established for the period April through October of the calendar year. The foregoing was proposed as a means of reducing the "inflated cost" of gas actually taken when the inability to take all of the gas which has been purchased exists. In conjunction with this, Staff proposed that a purchaser should be permitted to receive make-up gas for six months after the expiration of the original transportation authorizations.

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[36] The intrastate pipelines may file an abbreviated application as provided for in § 157.7 of the regulations of the Natural Gas Act. The application will be deemed sufficient if it includes a general description of the facilities and location (or a map of the same), a statement concerning the proposed rates, and the cost-of-service used to develop such rates.

[37] Natural Gas Act, Section 4(a), 15 U.S.C. Section 717c(a); FPC v. Texaco Inc., 417 U.S. 380, 394 (1974).

[38] 15 U.S.C. Section 717d.

[39] Supra, note 4, p. 6.

Upon review we find that it would be inappropriate to approve any form of percentage limitations upon the take-or-pay provision in sales contracts. Such action could establish both the upper and lower limits of such provisions and would be disadvantageous to the parties and the public interest. Individual applications shall be analyzed with regard to this provision. We do find, however, that additional flexibility should be provided to allow the industrial consumer an opportunity to take the gas for which it has paid and we will therefore adopt Staff's proposal to grant a six month extension for receipt of these volumes upon compliance with certain reporting requirements.

Accordingly, contracts of sale that contain a take-or-pay provision must include a provision permitting the extension provided for herein. Furthermore, when an extension is needed, the certificated pipeline shall file a request for extension with the Commission stating the volumes that need to be made up and the estimated time necessary. Extension for the full six month term will be deemed approved upon receipt by the pipeline of a letter from the Secretary of the Commission acknowledging the filing.

Many parties proposed modifications to current end-use restrictions imposed by Order No. 533 in order to allow the industrial customer greater flexibility in receiving the supply. United proposed that § 2.79 (e) and (f) be amended to allow a customer to take up to 50 percent of his authorized MDQ under his direct purchase contract in addition to his entitlement under his supplier's curtailment plan, prior to being obligated to reduce curtailment entitlements. Others suggest that the Commission should require that the pipeline system supply be the "first through the meter" whereby 533 supplies would be backed off. In other words, the 533 deliveries could be "banked" by the pipeline for future delivery to the industrial customers. The Ohio Commission requires the "first through the meter" option in all the contracts that it approves under its self-help program. It reported that there have been no objections by the participating pipelines to this provision.

Some of the parties suggested that the Commission should provide for an automatic one-year extension of the certificate's original term or such shorter period as is necessary for transportation of all make-up volumes outstanding under take-or-pay provisions of gas purchase contracts. Staff recommended that the end-use limitations be relaxed during the summer months to meet the dilemma that is particularly acute during this period. Under its proposal, the industrial consumer would be permitted to accept that volume of the 533 supply which would represent the difference between the actual pipeline supply and the total volume to which it is entitled under the pipeline's curtailment plan, regardless of the priority of service. An industrial consumer would be able to accept not only its pipeline supply, but a portion of its 533 pipeline supply limited by the total volumes to which it is entitled for all priorities of service. In the event that 533 volumes are still available, the Staff recommended that they be available to the industrial consumer for additional or new requirements.

We find that the priority restrictions on the use of 533 gas should not be changed. The 533 program was promulgated for the benefit of curtailed high priority users. If we were to implement the suggestions discussed above, gas supplies that were intended for these uses would be consumed for lower priority purposes, a result inconsistent with Commission policy. There is, however, the possibility that users could contract for storage service to store 533 gas during periods when it could not be used by the industrial for later delivery or arrange for an exchange of gas, and the Commission will entertain such applications.

A necessary factor of our decision to extend this policy is the promulgation of stricter reporting requirements with regard to alternate fuel capability. Order Nos. 533 and 533-A limited its application to situations "where gas is purchased for high priority uses that otherwise would be curtailed and without an alternate fuel capability." We intend to examine whether the industrial consumer has made a conscientious effort to develop and utilize alternate fuel capability. There are a number of industrial customers that do not have the ability to convert to more abundant fuels due to the present level of combustion technology. Nevertheless, there are many industrial processes which are classified as "process use" in most pipeline curtailment plans and are now using 533 supplies for which alternate fuel could easily be substituted. Certain information should be provided by the industrial customers in order for the Commission to have an opportunity to attempt to make this distinction. To accomplish this and meet the more stringent standard, the industrial consumer will have the burden of presenting substantial evidence that it has inquired into alternate fuel capability and conversion technology. The feasibility of implementing alternate fuel capability will be a primary consideration in our determinations of whether further extensions of existing authorizations should be granted subsequent to the first "rollover."

K. MISCELLANEOUS MATTERS

National Gypsum Co. supported the proposal that the Commission reexamine the criteria it has used in identifying high priority industrial uses. In determining which industrial uses are properly included in Priority 2 National Gypsum states the terms "feedstock" and "plant protection" have caused relatively little problems; however, "process gas" has been subject to multiple interpretations. In order to eliminate the uncertainty, it proposed an amendment to the language. Although the proposed definition may be preferable, staff and many of the parties do not support this amendment. We concur because this policy statement is not the appropriate vehicle to redefine what constitutes "process gas." A redefinition of this term should occur in the context of a reevaluation of Order Nos. 467, et seq., and 493-A.[illegible]

During the past two years, the Commission has followed the practice of issuing temporary certificates, when warranted, to applicants for permanent 533 certificates. All parties to the proceeding supporting continuation of the policy also support the issuance of temporary certificates. Staff concurs in the continuation of the administrative practice, but emphasize that all necessary information must accompany the application if the Commission is to review the application on an expeditious basis. We will continue the administrative practice of issuing temporary certificates where the necessary requirements have been met.

Several parties suggested that certain of the reporting requirements established under Order No. 533 should be modified. For example, it was suggested that the intermediary pipelines which transport the supplies between the producer and the pipeline providing service to the industrial customer should not be required to file monthly reports but that the primary transporting pipeline should provide all necessary information. It has also been urged that the monthly reporting requirements should be changed to provide a quarterly reporting. Upon our reassessment of the reporting requirements, we find that only the delivering pipeline need file a monthly report. Monthly information from intermediary transporting pipelines is unnecessary. However, we shall continue the requirement of monthly rather than quarterly reports from delivering pipelines in order to assist our assessment on the supply situation on major interstate pipelines during the winter.

III. CONCLUSION

Order No. 533 program was promulgated in 1975 as a statement of policy to clarify the circumstances under which the FPC would permit an interstate pipeline to transport certain sup-

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[illegible] FERC authority to take such action may be proscribed by section 402(a)(1)(E) of the DOE Act.

plies of gas not owned by the pipeline. Specifically, the FPC was responding to the ever-deepening curtailment situation on most jurisdictional pipelines by providing a method by which high priority industrial users could obtain supplemental supplies through direct purchase from producers. The criteria adopted for judging whether the proposed transportation of the purchased volumes was within the public convenience and necessity reflected judicial opinion[31] as well as a reveiw of the comments filed in response to the FPC's notice of proposed rulemaking.

When the FPC issued Order No. 533, it defined the program as "experimental" and requiring "empirical evidence of its merits"[32] if the policy were to be continued. To that end, the FPC published a notice of proposed rulemaking to review the policy statement and numerous comments were filed. After careful review and consideration of these submittals, this Commission has determined to continue the 533 policy.

The evidence in the record, comprised of the historical experience of the past two years, the comments filed by the parties, and the Staff reports to the Commission in the omnibus pipeline proceedings, demonstrate that the 533 policy has been a success. The program has provided high priority users with a method whereby they can mitigate the effects of curtailment by purchasing supplemental supplies directly from producers for the express purpose of decreasing the likelihood that curtailment will cause industrial plant shut-downs, which could produce a severe economic disruption in the communities affected. The gas transported under 533 and the overwhelming support of the program, as displayed in the comments, demonstrate the efficacy of the program. Since the conditions that required the 533 policy in the past persist today and are anticipated to continue in the near future, this Commission considers it prudent to maintain the policy in operation, as modified herein.

The Commission finds. (1) The notice and opportunity to participate in this proceeding with respect to the matters presently before the Commission through the submission, in writing, of data, views, comments and suggestions in the manner as described above are consistent and in accordance with all procedural requirements therefor as prescribed in section 553, Title 5 of the United States Code. Since the amendment prescribed here does not prescribe an added duty or restriction, compliance with the effective date requirements of 5 U.S.C. 553(d) is unnecessary.

(2) The amendment of Part 2, General Rules of Practice and Procedure, General Policy and Interpretations, Subchapter A, Chapter I, Title 18 of the Code of Federal Regulations, § 2.79, Policy With Respect To Pipeline Transportation Agreements, as herein prescribed, is necessary and appropriate for the administration of the Natural Gas Act.

(3) Since the modifications to § 2.79 prescribed herein which were not included in the notice of this proceeding are of a minor nature, and are consistent with the prime purpose of the proposed rulemaking, further notice thereof is unnecessary.

The Commission, acting pursuant to the provisions of the Natural Gas Act, as amended, particularly sections 7, 15 and 16 thereof (52 Stat. 824, 825, 829, 930; 56 Stat. 83, 84; 61 Stat. 459; 15 U.S.C. 717f, 717n, and 717o) orders:

(A) Part 2, Subchapter A, Chapter I, Title 18 of the Code of Federal Regulations is amended as set forth below, effective immediately:

§ 2.79 [Amended]

1. Section 2.79 is amended in paragraph (e) by deleting the "." and inserting in lieu thereof a phrase to read as follows:

* * * * *

(e) * * *

; *Provided further,* That the gas may be used during an authorized six month extension of the transportation authorization.

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[31] *FPC v. Transcontinental Gas Pipe Line Corp.*, 365 U.S. 1 (1961); *Arizona Public Service Co. v. FPC*, 483 F. 2d 1275 (D.C. Cir. 1973).

[32] Order No. 533, mimeo p. 28.

2. Section 2.79 is amended in paragraph (g) by inserting a new subdivision (viii) in subparagraph (1), by inserting new subdivisions (vii)-(xiii) in subparagraph (2), by revising subparagraph (1) in the introductory language, by revising subparagraph (2) (v) and (vi), and by revising subparagraph (3) to read as follows:

* * * * *

(g) * * *

(1) Interstate pipelines transporting gas pursuant to this policy must file the information set forth in subdivisions (i) through (vii) of this subparagraph. Intrastate pipelines transporting gas pursuant to this policy may file either a joint application with the interstate pipeline or an abbreviated application as provided in § 157.7, including the information set forth in subdivision (viii) of this subparagraph.

* * * * *

(viii) Provide a general description of the facilities and specify their location or include a map thereof; provide a statement concerning their proposed rates and Schedules L, M and N of § 154.63. For purposes of this subdivision (viii), there is no requirement that omission of other filing requirements be justified. For purposes of this subdivision (viii), the following provisions are waived:

(A) 18 CFR Part 154—Rate Schedules and Tariffs;

(B) 18 CFR 157.13—Form of exhibits to be attached to applications;

(C) 18 CFR 157.14—Exhibits;

(D) 18 CFR Part 159—Fees and annual charges under the Natural Gas Act;

(E) 18 CFR Part 201—Uniform system of accounts for natural gas companies; and

(F) 18 CFR Part 260—Statements and reports (schedules).

* * * * *

(2) * * *

(v) Provide a copy of the gas purchase contract with the producer underlying the proposed transportation, including the Btu content of the gas supply;

(vi) Provide a detailed description of the nature of the emergency necessitating the authorization of the proposed transportation including but not limited to the curtailment anticipated with respect to each priority of end use at the plant;

(vii) Provide a sworn statement by the consumer, supported by substantial evidence, that it has made a good faith effort to inquire into alternate fuel capability and conversion potential and further that it cannot develop such capability during the proposed use of 533 supplies;

(viii) Provide a complete description of the end use application and the facility in which the gas will be utilized, e.g., size and type of burner(s);

(ix) Provide a map showing the location of the wells and description of the acreage involved, along with the location of the nearest interstate and intrastate transportation facility;

(x) Indicate whether or not gas has previously been sold from the acreage and, if so, to whom, through what facilities and at what prices;

(xi) Provide available information as to:

(A) The ownership of adjoining acreage, and if productive, information as to whom the gas is being sold, and at what price;

(B) The current price, terms, and conditions of intrastate purchases for comparable gas produced within the immediate vicinity;

(C) Negotiations for the sale of the supply to any other purchaser (intrastate or interstate) and the suggested price;

(xii) If an intermediary participates in the transaction between the industrial customer and the producer and charges a fee, indicate the amount of the fee and terms of payment and the intermediary's affiliation, if any, with the producer and/or pipeline;

(xiii) If either the producer or the industrial customer assumes the cost of the construction of any gathering facilities in order to consummate the purchase, provide the cost, terms of payment, ownership and date of construction of the facilities.

(3) The information required by paragraph (g) (2) (i)-(xiii) of this section may be supplied by the applicant for a transportation certificate through submission of an appropriate affidavit from the non-resale industri-

al and commercial consumer whose gas is transported pursuant to this policy.

* * * * *

3. Section 2.79 is amended in paragraph (h) by revising subparagraph (1), and is amended by redesignating paragraph (j) as paragraph (k) and by inserting a new paragraph (j) to read as follows:

* * * * *

(h) * * *

(1) For each certificated transportation arrangement the delivering natural gas companies shall submit a monthly report to the Commission indicating the name of the producer, the volumes transported, the point of delivery to the distributor and/or non-resale industrial or commercial consumer, the name of the distributor and/or ultimate non-resale industrial or commercial consumer. An original and four copies of each such report shall be filed within 20 days after the end of each month included in the term of the transportation certificate. The delivering natural gas company shall submit a monthly report for any month during which gas was not transported.

* * * * *

(j) If an industrial consumer is unable to receive gas supplies for which it has paid under the take-or-pay provision in the underlying sales contract, the transporting pipelines may file a request for a six-month extension of the certificate authorization. The request shall include a statement of the undelivered volumes and the time necessary to complete delivery thereof. Upon receipt of a letter from the Secretary of the Commission acknowledging the filing, the requested extension shall be deemed approved.

(B) The Secretary shall cause prompt publication hereof in the FEDERAL REGISTER.

By the Commission.

KENNETH F. PLUMB,
Secretary.

APPENDIX A.—*Certificated applications*

	Prior to Nov. 1, 1975	Nov. 1, 1975 to Mar. 31, 1976	Apr. 1, 1976 to Oct. 31, 1976	Nov. 1, 1976 to Mar. 31, 1977	Apr. 1, 1977 to Dec. 1, 1977	Total volumes through Nov. 30, 1977
Applications	6	14	28	44	21	[1]113
Volumes/Mcf delivered	0	177,556	1,641,023	6,065,969	7,992,814	15,877,362

[1] 22 applications are currently under staff analysis.

APPENDIX B.—*Range of initial producer prices*

	Prior to Nov. 1, 1975	Nov. 1, 1975 to Mar. 31, 1976	Apr. 1, 1976 to Oct. 31, 1976	Nov. 1, 1976 to Mar. 31, 1977	Apr. 1, 1977 to Dec. 1, 1977[1]
Less than $1		1			
$1 to $1.24		3	1	1	
$1.25 to $1.49	1	8	12	4	2
$1.50 to $1.74	3	2	12	15	6
$1.75 to $1.99	2		1	10	15
$2 and above				12	15

[1] (Not included in above are 9 applications involving industry owned gas). Includes applications under staff analysis.

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[¶ 30,006]

43 F. R. 6764 (February 16, 1978)

[Docket No. RM75-25; Order No. 2]

PART 2—GENERAL POLICY AND INTERPRETATIONS

Amendments to Policy Regarding Certification of Pipeline Transportation Agreements; Corrections

FEBRUARY 9, 1978.

In FR Doc. 78-3365, issued February 1, 1978, and published at 43 FR 5362, February 8, 1978, on page 5368, 1st column, 3rd full paragraph, last sentence, change "The transportation of consumer-owned gas or reserves-in-place for a period not exceeding two years can be construed as falling within the scope of the policy." to read "Applications for transportation of consumer-owned gas or reserves-in-place made pursuant to § 2.79 for a period not exceeding two years may be construed as falling within the scope of the policy."

Page 5369, 1st column, 1st full paragraph, line 11, change "intrastate" to read "interstate".

KENNETH F. PLUMB,
Secretary.

[FR Doc. 78-4300 Filed 2-15-78; 8:45 am]

[¶ 30,007]

43 F. R. 6765 (February 16, 1978)

SUBCHAPTER A—GENERAL RULES

[Docket No. RM78-5]

PART 3 ORGANIZATION; OPERATION; INFORMATION AND REQUESTS

Organization of the Commission; Establishment of Oil Pipeline Board; Delegation of Authority to Oil Pipeline Board

AGENCY: Federal Energy Regulatory Commission

ACTION: Final rule.

SUMMARY: The Commission is establishing an employee board to handle several of the functions transferred from the Interstate Commerce Commission concerning the regulation of the transportation of oil and oil by-products by pipeline. This action will expedite the handling of numerous oil pipeline filings and applications.

EFFECTIVE DATE: February 10, 1978.

FOR FURTHER INFORMATION CONTACT:

Kenneth F. Plumb, Secretary 202-275-4166.

FEBRUARY 10, 1978.

Jurisdiction over oil pipelines, as it relates to the establishment of rates or charges for the transportation of oil by pipeline or to the establishment of valuations for pipelines, was transferred from the Interstate Commerce Commission (ICC) to the Federal Energy Regulatory Commission (FERC), pursuant to sections 306 and 402 of the Department of Energy Organization Act (DOE Act), 42 U.S.C. 7155 and 7172, and Executive Order No. 12009, 42 FR 46267 (September 13, 1977).

Section 17(2) of the Interstate Commerce Act (Act) authorizes the FERC to delegate any of its work, business, or functions to a board of employees. The ICC had established six (6) boards of employees to administer, inter alia, its functions related to the regulation of oil pipelines. These are the Suspension and Fourth Section Board, Valuation Board, Special Permission Board, Released Rates Board, Tariff Rules Board and Accounting Board. The FERC likewise believes that a board of employees is necessary for the proper administration of its oil pipeline functions.

However, because of the relatively small percentage of business generated by common carriers by oil pipeline with respect to the ICC boards, compared with the business generated by carriers by other modes, a single board should be able to carry out the FERC's functions in all of these areas.

For the present, practice before the Oil Pipeline Board will be governed by the ICC's rules of practice, 49 CFR Part 1100. See section 705 of the Department of Energy Organization Act, 42 U.S.C. 7295. The FERC will closely monitor Oil Pipeline Board activities and will revise the rules of practice if such action is warranted.

Pursuant to section 17(2) of the Act, the ICC delegated authority to review orders of employee boards to Divisions of the Commission. Exceptions to initial decisions by Administrative Law Judges are reviewed by employee Review Boards. Section 17(a) of the Act, however, requires that a Division consist of three (3) Commissioners. Inasmuch as FERC is comprised of only five (5) Commissioners, establishment of Divisions at this time appears inappropriate. While authorized to do so, the FERC has not yet established employee Review Boards. The authority to review decisions and orders of the Oil Pipeline Board will therefore be vested in the full FERC. In addition, any reference to a Commission "Division" or a "Review Board" in the Act or Rules (49 CFR Part 1100) shall be deemed to refer to the full FERC.

The Oil Pipeline Board shall also be delegated the authority to certify to the full FERC any matter which, in its judgment, should be passed upon by the Commission. Moreover, the Oil Pipeline Board will be given the authority to determine whether a matter should be set for oral hearing or whether it should be handled under the modified procedure pursuant to Rules 43 and 52 of the ICC's rules of practice (49 CFR 1100.43 to 1100.52).[1]

A separate administrative order of the FERC Chairman will designate the Oil Pipeline Board members, specify the chairman, and establish the effective date for implementation of this order and operation of the Board.

The Commission finds: (1) The amendments to the FERC's general rules herein adopted are necessary and appropriate in carrying out the provisions of the Interstate Commerce Act.

(2) The amendments herein adopted will assist the FERC in carrying out its responsibilities under section 4, 6(3), 6(6), 15(7), 19a, and 20(1), 20(2), 20(3), 20(4), 20(5), 20(11) of the Interstate Commerce Act.

(3) Pursuant to section 705 of the Department of Energy Organization Act, the Interstate Commerce Commission's rules of practice contained in 49 CFR Part 1100 will govern proceedings before the Oil Pipeline Board until such rules of practice are amended or revoked by the FERC.

(4) Any reference to a Commission "Division" or a "Review Board" in the Act or rules of practice (49 CFR Part 1100) should be deemed to refer to the full FERC for purposes of the operation of the Oil Pipeline Board herein established and review of its actions.

(5) Since the amendments herein adopted involve matters of Commission organization and procedure, and good cause exists that they be made effective immediately, compliance with the notice, hearing, and effective date provisions of 5 U.S.C. 553 is unnecessary.

The Commission, acting pursuant to section 17(2) of the Interstate Commerce Act and in accordance with 5 U.S.C. 552, orders:

(A) Paragraph "(d)" of § 3.4 Title 18 of the Code of Federal Regulations is amended by adding thereto subparagraph "(14)" as follows:

§ 3.4 Organization.

* * * * *

(d) * * *

(14) The Oil Pipeline Board, responsible for carrying out the Commission's functions under sections 4, 6(3), 6(6), 15(7), 19a, and 20(1), 20(2), 20(3), 20(4), 20(5), 20(11) of the Interstate Commerce Act. Any reference to a Commission "Division" or a "Review Board" in the Interstate Commerce Act or rules of practice (49 CFR Part 1100) shall be deemed to refer to the full FERC for purposes of the operation of the Oil Pipeline Board herein established the review of its actions.

(B) Section 3.5 of Title 18 of the Code of Federal Regulations is amended by adding thereto paragraph "(e)", as follows:

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[1] This contrasts with ICC procedure which delegated to the Chairman of a Division the authority to decide whether a matter should be handled under the modified procedure or set for oral hearing.

§ 3.5 Delegations of final authority.

* * * * *

(e) The Oil Pipeline Board to:

(1) Act on all matters arising out of Section 15(7) of the Interstate Commerce Act, 49 U.S.C. 15(7), including but not limited to the authority (i) initially to dispose of these matters, by declining to suspend a rate or a classification, rule or practice and ordering an investigation; (ii) to suspend and institute investigations into rates, fares, charges, and practices; and (iii) prior to the submission of evidence, to discontinue any proceeding when the proposed rate, classification, rule or practice has been cancelled.

(2) Issue valuation reports pursuant to Section 19(a) of the Interstate Commerce Act, 49 U.S.C. 19a, in matters which do not involve taking testimony at a public hearing or the submission of evidence by opposing parties in the form of affidavits.

(3) Act on matters arising under section 4 of the Interstate Commerce Act, 49 U.S.C. 4, except proceedings made the subject for formal hearing, or matters arising from general increase proceedings.

(4) Grant special permission or other permissible waivers of rules regarding tariffs or schedules under section 6(3) of the Interstate Commerce Act, 49 U.S.C. 6(3), including authorization for the cancellation of suspended tariffs or schedules that have not involved taking testimony at a public hearing or the submission of evidence by opposing parties in the form of affidavits.

(5) Act on matters arising under section 6(6) of the Interstate Commerce Act, 49 U.S.C. 6(6), related to the prescription of regulations concerning the form and manner in which tariffs required to be filed shall be published, filed, and posted, including the institution of rulemaking proceedings for the purpose of prescribing new or changed regulations, except matters involving taking testimony at a public hearing or the submission of evidence by opposing parties in the form of affidavits.

(6) Act on matters arising under sections 20(1), 20(2), 20(3), 20(4) and 20(5) of the Interstate Commerce Act, 49 U.S.C. 20(1), (2), (3) (4), (5), including prescription of a uniform system of accounts, rates of depreciation for property, and forms for accounts, records, and memoranda kept by oil pipeline carriers.

(7) Act on matters arising under section 20(11) of the Interstate Commerce Act, 49 U.S.C. 20(11), insofar as they relate to applications for authorization to establish released rates and ratings that have not involved taking testimony at a public hearing or the submission of evidence by opposing parties in the form of affidavits.

(8) Determine whether the investigation of suspended tariff schedules should be set for oral hearing before an Administrative Law Judge or handled under the modified procedure as described at 49 CFR 1100.43 to 1100.52.

(9) Certify to the full FERC any matter which the Oil Pipeline Board believes should be passed upon by the Commission.

(C) By separate administrative order the Chairman of the FERC shall designate the Oil Pipeline Board members, specify the Chairman of such Board and establish the effective date for implementation of this order and operation of the Board.

(D) The Secretary shall cause prompt publication of this order in the FEDERAL REGISTER.

By the Commission.

KENNETH F. PLUMB,
Secretary.

[FR Doc. 78-4307 Filed 2-15-78; 8:45 am]

[¶ 30,007A]

43 F. R. 7365 (February 22, 1978)

DELEGATION AND ASSIGNMENT OF FUNCTIONS BY THE SECRETARY OF ENERGY TO THE FEDERAL ENERGY REGULATORY COMMISSION RELATING TO DISTRIGAS CORP. AND DISTRIGAS OF MASSACHUSETTS CORP.

AGENCY: Department of Energy.

ACTION: Notice.

SUMMARY: Notice is hereby given of the delegation and assignment by the Secretary of Energy to the Federal Energy Regulatory Commission of the authority to carry out functions vested

in the Secretary under the Department of Energy (DOE) Organization Act as those functions relate to the decision of all issues pending for resolution in *Distrigas Corp.* and *Distrigas of Massachusetts Corp.*, ERA Docket Nos. 77-007-LNG and 77-011-LNG, FPC Docket Nos. CP70-196, et al., CP77-216, and CP77-217, to the extent such issues have not been decided by the Order on Importation of Liquefied Natural Gas from Algeria in ERA Docket No. 77-011-LNG, December 31, 1977.

EFFECTIVE DATE: February 22, 1978.

FOR FURTHER INFORMATION CONTACT:

Martin S. Kaufman, Department of Energy, Office of General Counsel, 12th and Pennsylvania Avenue, NW., Room 5116, Washington, D.C. 20461, Telephone: 202-566-9380.

SUPPLEMENTARY INFORMATION: The Department of Energy (DOE) was established by the DOE Organization Act, Pub. L. 95-91, 42 U.S.C. 7101, et seq. (1977) (the Act), which was enacted on August 4, 1977. The effective date of the Act was prescribed as October 1, 1977 by Executive Order 12009, dated September 13, 1977 (42 FR 46267, September 15, 1977).

Sections 401-407, 503 and 504 of the Act set forth the jurisdiction and authority of the Federal Energy Regulatory Commission (the Commission), the independent regulatory commission within DOE. These sections describe those functions previously performed by the Federal Power Commission and the Interstate Commerce Commission that are transferred to, and vested in, the Commission by the Act. These sections also describe the role with respect to appeals of certain Remedial Orders issued by the Secretary, and its role with respect to denials of adjustments to certain rules, regulations and orders issued by the Secretary.

In addition to jurisdiction over the functions transferred to, and vested in, the Commission by the Act, section 402(e) provides that the Commission will have jurisdiction over other matters that the Secretary may assign to it, after public notice is given of such assignment:

> In addition to the other provisions of this section, the Commission shall have jurisdiction over any other matter which the Secretary may assign to the Commission after public notice * * *.

Section 642 of the Act gives the Secretary a general power of delegation:

> Except as otherwise expressly prohibited by law, and except as otherwise provided in this Act, the Secretary may delegate any of his functions to such officers and employees of the Department as he may designate, and may authorize such successive redelegations of such functions within the Department as he may deem to be necessary or appropriate.

Pursuant to these provisions of the Act, public notice is hereby given that the Secretary delegates and assigns to the Commission the authority to carry out certain functions which by the Act are transferred to, and vested in, the Secretary. The assignment is in the form of a delegation, as are all delegations of authority made by the Secretary.

On December 31, 1977 the Administrator of the Economic Regulatory Administration, acting pursuant to DOE Delegation Order 0204-4, October 1, 1977, issued an Order on Importation of Liquefied Natural Gas from Algeria in *Distrigas Corp.* and *Distrigas of Massachusetts Corp.*, ERA Docket No. 77-011-LNG. That Order approved the importation of LNG into the U.S. from Algeria.

The delegation herein gives to the Commission the authority to carry out such functions as are vested in the Secretary to regulate natural gas imports under Section 301 and 402(f) of the DOE Act with respect to all of the issues remaining to be decided in related applications currently pending before DOE. These include issues relating to environment and safety inherent in the siting of an LNG terminal facility at Everett, Massachusetts, the construction of additional facilities at that site, approval of rates and tariffs, and authorization of sales for resale, in *Distrigas Corp.* and *Distrigas of Massachusetts Corp.*, ERA Docket Nos. 77-007-LNG and 77-011-LNG, FPC Docket Nos. CP70-196, et al., CP77-216 and CP77-217, which issues arise out of the applications filed by Distrigas Corp. and Distrigas of Massachusetts Corp., to the extent that such issues have not been decided by the Order on Importation of Liquefied Natural Gas From Algeria, ERA Docket No. 77-011-LNG, December 31, 1977. The delegation order authorizes the Commission to impose such contingency plan requirements as the Commission deems necessary and appropriate.

(Department of Energy Organization Act, Pub. L. 95-91; E. O. 12009, 42 FR 46267.)

Issued in Washington, D.C., on February 15, 1978.

[¶ 30,008]

43 F. R. 8118 (February 28, 1978)

SUBCHAPTER G—APPROVED FORMS, NATURAL GAS ACT

[Order No. 526-C; Docket No. RM74-16]

PART 260—STATEMENTS AND REPORTS (SCHEDULES)

Natural Gas Companies Annual Report of Proved Domestic Gas Reserves, Form No. 40

AGENCY: Federal Energy Regulatory Commission.

ACTION: Order granting rehearing or reconsideration in part and denying stay.

SUMMARY: Order No. 526-C of the Federal Energy Regulatory Commission (FERC) amends the regulations prescribing Form No. 40, Natural Gas Companies Annual Report of Proved Domestic Gas Reserves, and modifies the attestation clause of Form No. 40 in response to the applications of Gulf Oil Corp. and several other natural gas companies for rehearing or reconsideration of Order No. 526-B issued June 30, 1977 by the Federal Power Commission, predecessor of the FERC, all in Docket No. RM74-16. (42 FR 38556, July 29, 1977.) The amendments to the regulations broaden the exemptions from the filing requirements applicable to Form No. 40 with the result that fewer companies will be required to file Form No. 40. The procedure for the treatment of confidential data reported in Form No. 40 is also established by Order No. 526-C. The FERC rejects the arguments of the companies that they should not be obliged to report their natural gas reserves on a reservoir basis and that non-operating working interest owners should be excused from reporting the reserves to which their interests relate. Amoco Production Co.'s motion for a partial stay of Order No. 526-B is denied by the FERC. Form No. 40 submittals in arrears must be filed by March 1, 1978, but Form No. 40 submittals for the calendar year 1977 are not required to be filed prior to April 1, 1978.

DATES: Form No. 40 submittals in arrears must be filed by March 1, 1978. Form No. 40 submittals for calendar year 1977 must be filed by April 1, 1978.

ADDRESS: Form No. 40 submittals must be filed with: Kenneth F. Plumb, Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

Robert L. Baum, Deputy General Counsel, Federal Energy Regulatory Commission, Room 8000, Washington, D.C. 20426, 202-275-4333.

KENNETH F. PLUMB,
Secretary.
FEBRUARY 17, 1978.

On October 1, 1977, pursuant to the provisions of the Department of Energy Organization Act (DOE Act), Pub. L. 95-91, 91 Stat. 565 (August 4, 1977) and Executive Order No. 12009, 42 FR 46267 (September 15, 1977), the Federal Power Commission ceased to exist and its functions and regulatory responsibilities were transferred to the Secretary of Energy and the Federal Energy Regulatory Commission (FERC) which, as an independent commission within the Department of Energy, was activated on October 1, 1977.[1]

The "savings provisions" of section 705(b) of the DOE Act provide that proceedings pending before the FPC on the date the DOE Act takes effect shall not be affected and that orders shall be issued in such proceedings as if the DOE Act had not been enacted. All such proceedings shall be continued and further actions shall be taken by the appropriate component of DOE now responsible for the function under the DOE Act and regulations promulgated thereunder. The functions which are the subject of this proceeding were specifically transferred to the FERC by section 402(a)(1) or 402(a)(2) of the DOE Act.

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[1] The "Commission" when used in the context of an action taken prior to October 1, 1977, refers to the FPC; when used otherwise, the reference is to the FERC.

The joint regulation adopted on October 1, 1977 by the Secretary and the FERC entitled "Transfer of Proceedings to the Secretary of Energy and the FERC," 10 CFR ——: *Provided*, That this proceeding would be continued before the FERC. The FERC takes action in this proceeding in accordance with the above mentioned authorities.

The proceeding relates to the issuance of FPC Form No. 40, which requires that certain jurisdictional producers submit data on proved domestic gas reserves including data on a reservoir basis. The FPC originally issued Form 40 by Order Nos. 526 and 526-A,[a] but these orders were set aside and remanded in *Union Oil Co. of California v. FPC*, 542 F. 2d 1036 (CA9-1976). On June 30, 1977, the FPC issued Order No. 526-B, —— FPC ——, in response to the Court's remand and again issued Form 40 which required data in Schedule B on a reservoir basis. The following parties filed applications for rehearing of Order No. 526-B on July 29, 1977, Gulf Oil Corp. and the Superior Oil Co., and Amoco Production Co.; on August 1, 1977, Amerada Hess Corp., Tenneco Oil Co., Exxon Corp., Marathon Oil Co., and C&K Petroleum, Inc. C&K Offshore Co. and C&K Marine Production Co. Jake L. Hamon on August 8, 1977, Union Oil Co. on November 14, 1977, and Texico Inc. on November 23, 1977, filed untimely applications for rehearing or reconsideration, which must be treated as applications for reconsideration. On August 5, 1977, Amoco Production Co. moved for a partial stay of Order No. 526-B.

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[a] —— FPC ——, issued February 25, 1975; and —— FPC ——, issued August 18, 1975.

The filings raise and discuss the following points:

(1) Whether the producers should be required to file reserve information on a reservoir basis;

(2) Whether all working interest owners should be required to report on the reserves in question or whether it would be sufficient if only the operator reported except where the operator is a non-jurisdictional or a non-reporting company;

(3) Whether regulations should be issued to prevent the release of confidential information pending procedures to protect the producers;

(4) Whether a stay of Form 40 should be granted.

RESERVOIR REPORTING

Some producers object to being required to supply information on a reservoir basis. They contend, as they have previously, that supplying such information will be time-consuming and expensive and in some cases, where the data are not available, not productive of accurate information. They also argue that the FPC's conclusions about the need for such data were not based on substantial evidence and that the record does not provide substantial evidence upon which to ground these conclusions.

Gulf and Superior quote from the Court's opinion in *Mobile Oil Corporation* v. *FPC*, 483 F. 2d 1238 (D.C. Cir., 1973) to the effect that informal comments cannot create a record that satisfies the substantial evidence test even if controverting information is submitted in the form of comments by adverse parties. They contend that there must be an adversary proceeding. We disagree.[3]

The proceeding to which the Court directed attention in *Mobile* involved a rulemaking proceeding which set rates for certain transportation services as distinguished from this proceeding which involves a rulemaking designed to promulgate a data gathering form. *Mobile* does not provide convincing precedent that the procedures followed by the FPC were not satisfactory to create a record containing substantial evidence to support the requirements of Form 40. In *Mobile*, the Court cited its decision in *City of Chicago* v. *FPC*[4] to establish the appropriate standard for evaluating the adequacy of administrative procedures:

> [T]he "primary objective is the acquisition of information which will enable the Commission to carry out effectively the provisions of the Natural Gas Act." (*City of Chicago*, at 744.) To this end, the Commission should "realistically tailor the proceedings to fit the issues before it, the formation it needs to illuminate those issues and the manner of presentation * * *." (Id.)[5]

The Court in *Mobil* provided further guidance on the type of inquiry the Commission should follow in establishing its procedures. The Court states: "[i]f a relatively high degree of evidentiary support is required in establishing a factual predicate, the rulemaking procedures must be designed to create this." (483 F. 2d at p. 1257.) Applying this standard to the instant proceeding, the Court in *Union* said that, while there must be evidence that reservoir data is available to the producers, the Commission need not conduct an adjudicatory hearing or any oral hearing in order to obtain such evidence (542 F. 2d at p. 1041). In our opinion, the staff's statement of position filed February 10, 1977 (Ex. 1) along with other data in the record supports the FPC's action and is relied on in the instant matter. Furthermore, it is clear that the factual predicate needed to develop a data information form for regulatory use is much less subject to dispute than that needed to establish transportation rates.[6] Most of the arguments made by the Applicants on rehearing were previously made and discussed by the FPC in Order No. 526-B, but further discussion by the FERC will clarify our position.

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[3] In addition, the United States Court of Appeals for the Fifth Circuit similarly found such an argument unpersuasive. *Superior Oil Co.* v. *FERC*, 563 F. 2d 191 (1977). There, the Court discussed *Mobile* and said (563 F. 2d at 201, n. 18):

Our decision is not inconsistent with *Mobile Oil Co.* v. *FPC*, *supra*, *Placid Oil Co.* v. *FPC*, 483 F. 2d 880 (5th Cir. 1973), *aff'd sub nom. Mobile Oil Co.* v. *FPC*, 417 U.S. 283, 94 S. Ct. 2328, 41 L. Ed. 2d 72 (1974), and *Shell Oil Co.* v. *FPC*, 520 F. 2d 1061 (5th Cir. 1975) cert. denied 426 U.S. 941, 96 S. Ct. 2661, 49 L. Ed. 2d 394 (1976). These cases involved rate making or the regulation of rates rather than policy decisions.

[4] 147 U.S. App. D.C. 312, 458 F. 2d 731 (1971), cert. denied, 405 U.S. 1074, 92 S. Ct. 1495, 31 L. Ed. 2d 808 (1972).

[5] 483 F. 2d at 1252.

Gulf and Superior say that the accuracy of the reserve estimates cannot be improved by making the estimate on a reservoir basis rather than on a field or lease basis. They contend that there are no available data for the older reservoirs so that arbitrary allocations must be made with the result that an estimate of reserves on a reservoir basis will be no more accurate than an estimate on a field or lease basis.

In Order No. 526-B, the Commission pointed out that to make an accurate estimate for the field it would be necessary to make an estimate for each reservoir. In those few instances where there are no available reservoir records, an estimate by allocation or any other reasonable means may be employed. Total reserve figures will be more accurate where based to the greatest degree possible on reservoir data available to the producers. In Opinion No. 526-B, it is shown that a large number of the producers have been able to file their data on a reservoir basis.

It is contended that the Commission has ignored the testimony and producer comments on the burden of complying with reservoir-basis reporting. The FPC did not ignore the record (see Opinion No. 526-B, pp. 9-10). The FPC said that it realized that the present data did not always permit accurate analysis of a limited number of reservoirs, and that in such cases the FPC would not ask for anything more than what is feasible. The FERC expects that the affected producers will employ a reasonable method of allocating gas to these few reservoirs and will accept such data even though it may not be as accurate as that data produced by the most rigorous techniques.

It is further argued that the reservoir data are not necessary in considering pipeline applications for certificates or pipeline depreciation, because the pipelines supply sufficient data on Form 15.[7] However, reporting by the producers, who are most familiar with the reserves, should be available to the Commission in considering these pipeline questions in order to compare producer and pipeline reserve estimates by reservoir and to determine the availability of reserves in reservoirs which have not yet been produced by producers and which have not been reported by the pipelines. The data are also necessary to check the accuracy of the aggregate figures upon which the Congress, the public and the Commission must rely for decision-making purposes.

Apart from increasing the accuracy of reserve data and auditing procedures as discussed in Order No. 526-B, we note that Form 40 gives us data on the depths of reservoirs that could be used for granting price incentives, where necessary, for deeper drilling (See § 2.76 of the Commission's rules); the data on committed and uncommitted gas reserves which will enable us to determine whether producers are living up to their contracts to deliver gas; and the means to compare proved reserves with cumulative production on a reservoir basis in order to determine which gas reserves are close to depletion.

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[6] *Superior Oil Co. v. FERC, supra.*

[7] Form No. 15, Annual Report of Gas Supply for Certain Natural Gas Pipelines, Order No. 546, —— FPC ——, March 8, 1976, 18 CFR 260.7

Gulf Oil and Superior suggest that producers who cannot file by reservoir be required to file by field according to state-designated nomenclature, and that, in this way the Commission would have a common data base for those producers. This suggestion is not satisfactory since there would not be a common basis for comparison between those reporting on a field basis and those using the reservoir method. Nor is the nomenclature uniformly defined by the producing states.

Under the FPC's orders in this docket, all natural gas companies who, together with their affiliates, produced for direct sale and for resale in interstate commerce in excess of 250,000 Mcf for the reporting year will be required to file Form 40. However, those companies who, together with their affiliates, produced over 250,000 Mcf per year; but who alone own less than 20 Bcf in reserves would be exempt from filing Schedule B of Form 40.

After examining the Form 40 filings submitted for 1974 and other data, we conclude there is an adequate basis for further limiting the number of reporting entities without loss of information necessary to our regulatory functions. Highly cognizant of the need to lessen the burden of compliance with information requirements of government where to do so would not impair its regulatory purposes, this Commission on its own motion has determined to modify the initial threshold levels for reporting established in FPC Order No. 526-B. All natural gas companies which, together with their affiliates, produced for direct sales and/or sale for resale in interstate commerce 1,000 MMcf or less of gas during the report year will be exempted and Schedule B will be filed only by producers who own more than 100 Bcf of gas reserves.

For 1974, 555 producers with more than 250,000 Mcf of total production filed Form 40 reports. These 555 producers accounted for about 82.2 percent of total natural gas production as estimated by the American Gas Association (AGA).[8] However, in 1974 only 378 of the Form 40 respondents reported over 1,000 MMcf of production but these entities accounted for about 81.7 percent of the production as estimated by AGA. Thus, applying the proposed reporting rules to the 1974 data would have resulted in a 31 percent reduction in the number of reporting units but only a minor reduction in the percentage of total industry production included in the coverage.

The basic relationships between the number of working interests and reserves and production for 1974 are schematically indicated in the attached figures.[9] Also shown are two charts that depict the amount of production and reserves by each of the largest 720 working interests in 1974. For each working interest (the "N"th interest, i.e., the 420th largest working interest or the 370th largest interest, etc.) one can obtain an idea of the size of the reporting unit measured either by production or reserves.

The 1974 data are used to illustrate the general orders of magnitude of reporting requirement reductions on the one hand and information reduction on the other. Industry changes, changes in reporting definitions and other changes since 1974, mean that the number of working interests reporting 1976 data will differ.

Another estimate of the impact of the change in reporting requirements is shown in Table 1, attached, which summarizes the responses of large firms for 1973 on Forms 301-A and 301-B and small firms on 314-B. Over 5,000 small firms were tentatively identified and about half submitted Form 314-B reports. Of these 2,563 firms, only 639 had jurisdictional sales of over 250 MMcf and only 245 had jurisdictional sales over 1,000 MMcf. Form 301-A was filed by 590 large producers or affiliates of large producers. Part II of the table reveals that the more than 400 working interests with jurisdictional sales of greater than 250

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[8] AGA production and reserve estimates are used as bench marks only and imply neither acceptance nor rejection of these as defining the total statistical universe.

[9] See Appendices A, B, C, and D.

MMcf but less than 1,000 MMcf accounted for only 1.8 percent of the total jurisdictional sales reported. Note that even using a 250 MMcf cutoff point, on the basis of the 1973 figures, three-fourths of the small firms would not be included in the data base.

The current threshold for filing Schedule B of form 40, 20 Bcf of reserves, yielded approximately 254 filings in 1974. These 254 companies accounted for approximately 82.05 percent of AGA's estimated total reserves. A requirement of 100 Bcf of reserves in 1974 would have reduced the number of filings to approximately 116, a reduction of 60 percent in the number of reports filed. These 116 reports accounted for approximately 79.25 percent of AGA's estimated 1974 total reserves.

As indicated above, we believe these reductions in the reporting requirements will alleviate some of the reporting burden while not causing a loss of necessary data. While we have analyzed this issue using 1973 and 1974 data, we believe the conclusions reached apply to the current situation. Our easing of the reporting requirements will have its greatest impact on small producers by reducing the number who must file Form 40. However, any further increase in the filing thresholds at this time could result in a lost of significant data which the Commission needs to perform previously articulated regulatory responsibilities.

In sum, the FERC has analyzed the reporting burden on the smaller entities in the natural gas industries and balanced this with the marginal contribution to effective regulation of the data lost as a result of changing the reporting requirements. We have concluded that the substantial reduction in reports required merit this change in requirements. Where a reduction of the filing burden of this magnitude can be permitted with no loss of data necessary to perform the FERC's regulatory responsibilities, the Commission feels compelled to do so in order to protect the regulated entities from unnecessary reporting requirements. However, we feel any further reduction in reporting requirements would result in an unacceptable loss of information.

C&K Petroleum argues that there is a relatively larger burden placed upon small producers. The threshold modifications in this order will alleviate to a considerable extent the reporting burden on small producers by reducing the number of reporting entities by more than half on a reserve basis and by almost a third for all schedules of Form 40. The FERC here exercised its responsibility to assure that the data requested are only those data necessary to permit it to perform its regulatory functions. Nonetheless, we emphasize that we have regulatory responsibilities that involve all sectors of the natural gas industry firms. We need adequate and accurate information about both large and small firms. It is not enough merely to account for most of the industry's production and reserves. The Commission's assigned tasks necessitate information about small producers. We note with regret that even if we were to have kept the 250 MMcf cut-off point, we would not have obtained data from the majority of working interests. (See Table 1 attached). Although Form 40 is not the appropriate vehicle for dealing with this problem, we will continue to explore ways to improve FERC's data base with respect to the small producer sector of the industry.

Clarification has also been requested as to how to calculate whether a producer is required to file. Pursuant to the Commission modification to the threshold levels ordered therein, producers who, together with their affiliates, produce 1,000 MMcf or less per year are exempt from filling any of the schedules required by Form 40. However, if a producer, together with its affiliates, produces 1,000 MMcf or more per year it must file Form 40. The producers that own 100 Bcf or less of dry gas reserves are not required to file Schedule B of Form 40. The 100 Bcf exemption from filing Schedule B applies to any individual member of a group of affiliates if that individual member owns 100 Bcf or less of dry gas reserves.

Finally, the FERC emphasizes the FPC's reference to the *Second Natural Gas Rate Cases*, —— F. 2d —— (D.C. Cir., June 16, 1977), in Order No. 526-B. The Court examined the Commission's estimate of drilling productivity based on data gathered by the American Gas Association, comments of the parties, and the FPC staff studies, and concluded that the evidence was the minimum upon which the Court would base its opinion. The Court was unwilling to remand the proceeding for further evidence because of the overriding need for certainty of natural gas prices and noted that the Commission was "building an administrative record for its Form 40, to permit its gathering of direct information on producers' reserves, rather than through statistical appraisal by the industry committee." (Slip opinion at 61.) "To sum up," the Court said, "we do not approve or embrace the AGA figures; we simply tolerate them for purposes of this proceeding. We expect that by the next biennium the Commission will have put into effect its own procedures for gathering reserves data." (Slip opinion at 62.)

The Form 40 data requested here are vital for carrying out this mandate. We stress that while we have attempted to accommodate industry suggestions the data specified in this order are essential to discharge FERC's duties.

Working Interest Reporting

A number of the applicants for rehearing object to the requirement that all working interest owners report the reserves to which their working interests relate. The producers argue that the operator has available the requisite geological and production data and can make the most accurate report. The non-operating working interest owners would have to acquire the necessary data at the cost of time and expense resulting in duplicative filings which might differ from one another. Where the operator is not a natural gas company or is not subject to the Form 40 reporting requirements, the producers on rehearing agree that the requirement of reporting should continue to rest on the working interest owners.

We believe that reserve data on a working interest basis are required in order to permit the FERC to develop a series of reporting forms which, when taken as a whole, will permit meaningful comparative analyses. In order to accomplish this goal of establishing an integrated reporting system for regulatory data, the set of reporting entities must be consistent. The Form 40 information is designed to report on an individual working-interest basis the productivity of drilling operations. Form 40 will provide information on the depths of drilling to the reservoirs, the reserves in those reservoirs, and the changes in such reserves. These data are then to be correlated with the cost data provided in Form 64.[10] Form 64 reports cost data on a working interest basis. The accurate matching of the average drilling productivity with the associated costs is necessary to determine the just and reasonable natural gas rate. To require the reporting on an operator basis only would necessitate an extrapolation of the operator data to a working interest basis in order to correlate the cost data with the productivity data. Such an additional analytical step will unnecessarily reduce the accuracy of the average production costs for rate-making purposes.[11] To the extent the FERC is able to improve the data upon which it must rely to exercise its major regulatory functions by requiring working interest reporting while imposing a minimal regulatory burden upon the reporting entities, the Commission feels compelled to do so. We will also request each reporting entity which has already filed for operated properties to supplement their filing with this information.

Confidentiality of Data

The Court in *Union* considered the FPC petition for rehearing of the Court's finding that the confidentiality policy set forth in Order No. 526

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[10] Recently upheld in *Superior Oil Co.* v. *FERC*, 563 F. 2d 191, (5th Cir., November 17, 1977).

[11] The Commission believes that a different case may be presented where a data request reaches more broadly to obtain data from all producers. In such a case, it may be appropriate to rely on operator reporting which identifies working interest ownership without loss of accuracy. In as much as this is a rehearing of a form originally issued to producers subject to FPC jurisdiction under the Natural Gas Act, the hypothetical case outlined above is not now before this Commission.

and 526-A was arbitrary and capricious, and concluded that:

> The Commission states that it is its practice not to release such data without giving notice to the parties. However, we find no regulation of the Commission to that effect, or committing the Commission to that practice, and the order under review makes no such commitment. The Commission merely stated that such data would be 'given confidential status * * * and left in the Commission files until further ordered by the Commission.' On its face, this is a reservation of unfettered discretion.

With regard to actions taken after remand of *Union*, Gulf and Superior argue that we have failed to consider regulations to protect from disclosure the confidentiality of information on Schedules B, C and D of Form 40. In denying a motion by Gulf to expand the present docket to consider specific rules concerning confidential reserve information the Commission said:

> However, we will hold administratively confidential those parts of Form 40 heretofore designated and will not make disclosure as an exercise of discretion on our part without affording the producers opportunity for a hearing. Where we are required by statute or otherwise to make disclosure to some other government body we shall notify the producer involved as much in advance as possible.

Gulf and Superior contend that the Commission's promise to notify producers and provide an opportunity for a hearing before disclosure is not an effective relinquishment of "unfettered discretion" particularly since one Commission cannot bind a subsequent Commission. Only by promulgating regulations, Gulf and Superior say, can the Commission deal adequately with the holding in *Union* that the reservation of discretion by the Commission to determine whether to disclose confidential reserve information is arbitrary and capricious.

We do not read the *Union* decision to require the promulgation of a regulation as Gulf and Superior contend. Nor do we read *Union* as holding that the Commission may not employ its administrative discretion in considering the question of disclosure. The decision only requires that the Commission articulate its procedure for considering data disclosure requests and the standard by which the Commission will render its decision. The Court's requirement that the producer be afforded an opportunity to voice its objection to the Commission before the release of the confidential data is fulfilled by permitting the producer and other interested parties to file written objections and comments which will be considered by the Commission prior to disclosure.[12]

The policy outlined below shall apply to the Form 40 data which the Commission recognizes is information encompassed within the exclusions to the Freedom of Information Act.[13] Although this information may be encompassed within the exclusions enumerated in the statute, this fact does not absolutely prohibit disclosure but leaves such a determination to the discretion of the agency which maintains custody of the data.[14] Nonetheless, it is the Commission's intent to respect the confidential nature of the data submitted.[15]

The Commission does, however, reserve the right to use the data in any judicial proceeding, in which it is a party or intervenor, any administrative rulemaking, adjudicatory or investigatory proceeding before the Commission, or in any such proceeding before other agencies in which it is a party or intervenor.

The Commission also reserves the right to disclose the data, after notice to the producer(s) who submitted the data, in any judicial proceeding in which the Commission is a party or intervenor, any administrative rulemaking or adjudicatory or investigatory proceeding before the Commission or another agency where the Commission is a party or intervenor. In such proceedings the Commission will attempt to limit the disclosure to only those data required to be disclosed in order to execute the Commission's statutory obligations. It is proper in such an instance, that the burden be placed on the person or entity that objects to such disclosure of the data to seek appropriate relief, if any, in a court of competent jurisdiction.

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[12] *United States v. Florida East Coast Railway Co.*, 410 U.S. 224, 93 S. Ct. 810 35 L. Ed. 2d 223 (1973).

[13] 5 U.S.C. Sec. 552(b) (4), (9); *Amerada Hess Corp.*, 50 FPC 1048 at 1050 (1973).

[14] *Pennzoil Co. v. FPC*, 534 F. 2d 625 (5th Cir. 1976).

[15] Id.

In instances where the request for disclosure is in the form of a lawfully issued subpoena from a Court or another agency, a duly constituted Congressional Committee or Subcommittee[16] or Chairman thereof, either by subpoena or formal written request, or an administrative agency pursuant to a mandatory request, it will be the Commission's policy to give notification as soon as is practicable to the affected reporting entity of the request for the data and that the Commission intends to comply therewith on a date certain. It is proper, in such an instance, that the burden be placed on the person or entity that objects to the Commission's disclosure of the data to seek appropriate relief, if any, in a court of competent jurisdiction or before the requesting entity. In complying with such a disclosure request, the Commission will, in its submission, advise the requesting person or entity that the reporting party has requested the FERC to treat the data sought as confidential and that the Commission has honored that request for its own purposes.

When FERC is requested by another administrative agency to disclose the data pursuant to a formal request to use the data for regulatory or enforcement purposes, the Commission will allow the affected reporting entity(ies) an opportunity to voice its (their) objection to the Commission by permitting the reporting party to file written objections which will be considered by the Commission prior to disclosure. In complying with such a disclosure request, the Commission will, in its submission, advise the requesting entity that the reporting party has requested the FERC to treat the data sought as confidential and that the Commission has honored that request for its own purposes.

When such a request is made for statistical purposes, the Commission will disclose the data, if at all, conditioned upon confidential treatment by the requesting agency. In all such cases the Commission will notify the producer(s) whose data is subpoened or otherwise requested as soon as practicable.

In cases where the FERC is requested by an individual or where the Commission decides to disclose Form 40 data for public information, the Commission will notify the affected reporting entity(ies) of the request, or the Commission's decision, and will permit them to submit written comments as to whether the Commission should comply with the request or disclose the information. The Commission has determined, however, that it is not inclined to disclose the data in response to such requests by individuals or for public information. Therefore, there will be a strong presumption against such disclosure.

In exercising its discretion as to whether to honor a nonmandatory data request, the FERC will follow the Court's mandate in *Union* for "a reasoned decision weighing their interest and that of the public before the Commission permits the release of such data, if it is to be released at all." In reaching a decision on disclosure the Commission will consider inter alia: (1) The nature of the data; (2) the extent to which disclosure will aid or impair the Commission's discharge of its statutory duties; (3) the extent of the harm or risk disclosure might cause to producers and to the general public; (4) available alternatives to disclosure; (5) availability of the data from other sources; and (6) the use to which the data is to be put.[17]

ATTESTATION CLAUSE

Union Oil with the support of Texaco, in its application for reconsideration contends that its Form 40 filings will comprise many pages of a very technical nature and cannot be reviewed and tested by any one person. It suggests that the attestation language, "* * * that he has read this report and is familiar with the contents thereon * * *" be deleted and replaced with the phrase "* * * that he has caused this report to be prepared by those individuals employed by the respondent who are most familiar with the subject matter * * *."

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[16] The Commission's policy recognizes that the House of Representatives and the Senate are organized into legally authorized committees and subcommittees.

[17] Cf. *Superior Oil Co. v. FERC*, —F. 2d 716 (5th Cir. 1977) (Nos. 76-2113, 76-2246, Nov. 17, 1977).

In order to alleviate the problem raised by Union, we are herein modifying the attestation clause as included in Appendix E to this order. The new attestation clause is adopted from the statement contained on all corporate income tax returns which must be signed by a corporate official. We recognize that the attestation clause contained in prior orders would have been difficult to comply with. This new attestation clause is similar to those that are regularly executed by corporate officials, is designed to insure the accuracy of the data submitted to enable the FERC to carry out its statutory function.

NEED FOR A STAY

A number of producers asked for various extensions of time in which to file Form No. 40 beyond the November 1, 1977, filing date covering the filing years 1974, 1975 and 1976 as specified in Order No. 526-B. By notice issued October 19, 1977, the Secretary granted an extension of the filing date to December 1, 1977.

Amoco asked for a stay of the November 1, 1977, filing date with respect to Schedule B of Form 40 for the years 1974, 1975 and 1976, pending completion of rehearing and judicial review. It was not our intention that Schedule B be filed for the years 1974 and 1975, but for 1976 and later years. We shall amend Order No. 526-B accordingly to make this clear. Apart from this its arguments citing *Virginia Petroleum Jobbers Ass'n* v. *FPC*, 259, 921 (CADC 1958), are not persuasive. We do not agree that it is likely to prevail on the merits. Nor will it be irreparably harmed if a stay is not granted. As the Court said mere injuries, however substantial, in terms of money, time, and energy necessarily expended in the absence of a stay, are not enough. There is no reason to assume that confidential data will be disclosed. It will not be done without consideration of the producers' objections (unless another government agency so requires under the authority of some other statute), and appeal can be made to a reviewing court. If a stay is granted, other parties and the public will clearly be injured by a stay assuming, as we do, that the Schedule B data is necessary to carry out the purposes of Form 40.

We shall therefore deny a stay as requested by Amoco. We postponed the initial filing date for the calendar years 1974, 1975 and 1976 from November 1, 1977, until December 1, 1977. In the instant order, we further extend the filing date for 1974, 1975, and 1976 from December 1, 1977, to March 1, 1978. We also extend the filing date for 1977 from April 1, 1978, to September 1, 1978. As a result of the filing requirements for Form 40 are as follows:

Report year	Filing date	Schedules required
1974	Mar. 1, 1978.	Schedule A and schedule D to A, as needed for footnotes.
1975	Mar. 1, 1978.	Do.
1976	Mar. 1, 1978.	Do.
		Reserves greater than 100 Bcf—schedule B and schedule D to B as needed for footnotes.
		Reserves of 100 Bcf or less—schedule D with volumes of reserve by State(s), subdivision(s) and district(s)
1977 and 1978 and later years.	Sept. 1, 1978 and Apr. 1 of the next year.	Schedule A and schedule D to A as needed for footnotes.
		Reserves greater than 100 Bcf—schedule B and schedule D to B as needed for footnotes.
		Schedule C and schedule D to C as needed for footnotes.
		Reserves of 100 Bcf or less—schedule C and schedule D to C as needed for footnotes.

In addition to the above schedules, a title page and an attestation must be filed for each of the report years.

The Commission further finds: (1) The assignments of error and grounds for rehearing of Order No. 526-B in the applications for rehearing or reconsideration filed herein present facts and legal principles which warrant certain modifications and clarifications as set forth herein.

(2) On its own motion, that the reporting thresholds for Form 40 and Schedule B of Form 40 should be modified as set forth herein.

(3) The procedure adopted herein for the treatment of confidential data meets the procedural requirements of the Administrative Procedure Act and the Freedom of Information Act and complies with the remand of the Court in *Union Oil Co. of California* v. *F.P.C.*, 542 F.2d 1036 (9th Cir., 1976).

(4) The conclusions of the FPC as expressed in Order Nos. 526-A and 526-B and the FERC as expressed in the instant order are based on substantial evidence as required in Section 19 of the Natural Gas Act.

(5) The notice and opportunity to participate in this proceeding with respect to the matters currently before the Commission are consistent and in accordance with all procedural requirements as prescribed in Section 553, Title 5 of the United States Code.

(6) The amendment to § 260.13 of Part 260 of the Commission's regulations and the modifications of Form 40 are necessary and appropriate for the administration of the Natural Gas Act.

The Commission orders: (A) The applications for rehearing or reconsideration filed by the applicants herein are denied except to the extent granted herein.

(B) Section 260.13, Part 260, Subchapter G of Chapter I, Title 18 of the Code of Federal Regulations, is amended to read as follows:

§ 260.13 Form No. 40, natural gas companies annual report of proved domestic reserves.

(a) The form of Natural Gas Companies Annual Report of proved Domestic Gas Reserve as F.P.C. Form No. 40 is adopted.

(b) Each person found by the Commission to be a natural gas company within the meaning of the Natural Gas Act, which together with its affiliate, associate, or subsidiary produced for direct sale and/or sale for resale in interstate commerce more than 1 Bcf of gas at 14.73 psia and 60 degrees Farenheit during the report year shall prepare and file with the Commission F.P.C. Form No. 40, as follows:

(1) An original and four copies of Schedule A; (2) an original copy of Schedule C; and (3) an original copy of Schedule D, as necessary.

(c) Each person found by the Commission to be a natural gas company within the meaning of the Natural Gas Act which owns more than 100 Bcf of dry gas reserves at 14.73 psia and 60 degrees Farenheit at the end of the report year shall prepare and file with the Commission F.P.C. Form No. 40, as follows:

(1) An original and four copies of Schedule A; (2) an original copy of Schedule B; (3) an original copy of Schedule C; and (4) an original copy of Schedule D, as necessary.

(d) Paragraphs (b) and (c) apply to calendar year 1976 and subsequent years, except that Schedule C is not required for 1976. The F.P.C. Form No. 40 shall be filed by March 1, 1978, for the calendar year ending December 31, 1976, by September 1, 1978, for the calendar year ending December 31, 1977, and thereafter shall be filed by April 1 of the year following the year to which the form applies.

(e) Any person subject to paragraph (b) who has not filed Schedule A for 1974 and 1975 shall do so by March 1, 1978.

(f) Schedule A shall be made available at the Commission's principal office for public inspection.

(g) Information filed pursuant to this section shall be filed under oath.

(C) The procedure adopted herein for the treatment of confidential data filed in Form 40 shall apply only to Form 40 data.

(D) The attestation clause of Form 40 is amended as shown in Appendix E attached below.

(E) The Secretary shall cause prompt publication of this order to be made in the FEDERAL REGISTER.

(F) The motion of Amoco Production Co. for a partial stay is denied.

(G) The effective date of this order shall be the date of issuance.

(H) The Secretary shall cause copies of Form No. 40, as modified by this order, to be transmitted to the Director of the Office of Management and Budget.

By the Commission.

KENNETH F. PLUMB,
Secretary.

[¶ 30,009]

43 F. R. 11691 (March 21, 1978)

PART 157—APPLICATIONS FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND FOR ORDERS PERMITTING AND APPROVING ABANDONMENT UNDER SECTION 7 OF THE NATURAL GAS ACT

Exemption of Certain Emergency Gas Transportation Arrangements During the Coal Emergency

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is issuing this amendment on an emergency basis to provide an exemption from the certification requirements of section 7 of the Natural Gas Act for certain emergency gas transportation arrangements during the current coal emergency. The purpose of the amendment is to encourage pipelines to provide transportation services as necessary to permit qualifying natural gas sellers to make short-term sales in interstate commerce to eligible electric utilites during the coal emergency period.

EFFECTIVE DATES: March 21, 1978; expires May 31, 1978.

FOR FURTHER INFORMATION CONTACT:

William L. Webb, Office of Public Information, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, 202-275-4006.

Walter A. Romanek, Director, Division of Coal Utilization, Economic Regulatory Administration, Room 7202, 2000 M Street NW., Washington, D.C. 20461, 202-254-3910.

SUPPLEMENTARY INFORMATION:

BACKGROUND

Due to the present and prospective unavailability of coal supplies to certain electric utilities in the United States as a result of the coal shortage, the potential exists for harm to the public health and safety due to circumstances such as the curtailment of electric power. Alternate fuels, such as natural gas, should be made available to electic utilites to assist in alleviating the effects of low coal supplies. The areas most affected by this coal shortage at the present time are western Pennsylvania, western Maryland, West Virginia, Ohio, Indiana, Kentucky, Michigan, Illinois, Tennessee, northern Alabama, North and South Carolina, Missouri, Wisconsin, and northern Mississippi. Coal supplies at many coal-fired electric generating plants in those areas have declined to critical levels. As of March 3, 1978, of the 28 utilities surveyed by the Commission's Office of Electric Power Regulation[1] two indicated that they have less than 30 days of supply remaining, while 22 report less than 60 days' supply in a system average. The remaining utilities had at least 60 days' supply available.

Some of these coal-fired generating plants have the capability of burning natural gas for at least a portion of their fuel requirements. For example, of the 28 major electric utilities surveyed, our information indicated that 8 have the capability to use natural gas in lieu of coal in at least some units. The total generating capacity of these units is almost 7,000 megawatts.

Reports received by the Commission so far this winter through regular monitoring of interstate pipelines indicate that natural gas supplies, including substantial emergency supplies, are adequate at this time to serve high priority uses. At the beginning of March 1978, underground working storage supplies of interstate natural gas pipelines were 777 Bcf, approximately 90 Bcf (13 percent) more than last year at that time. Net storage withdrawals through March 14, 1978, are expected to be approximately 90 Bcf, which means that working gas storage at this time may approximate last year's level of 686 Bcf. Any further depletion of storage inventories, including part of the remaining working gas inventory, will depend primarily on weather conditions. No industrial shutdowns due to natural gas curtailment are projected by interstate pipelines at this time, nor is any industrial shutdown anticipated on the basis of other information available to the Commission. The Commission will continue to monitor closely the supply and storage situation through the balance of winter and thereafter, and if that situation should deteriorate (or if coal supply conditions significantly improve), we will reevaluate this emergency program and consider early termination of the coal emergency period.

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[1] Includes the major utilities in the East/Central Area Reliability Council (ECAR), the Tennessee Valley Authority and several utilities in the Mid America Interpool Network.

CURRENT REGULATIONS

While natural gas may be available to alleviate some of the effects of the coal shortage, the Commission's Rules and Regulations related to short-term emergency purchases of natural gas may not provide sufficient latitude to ensure that the natural gas will be available for that purpose. Section 2.68 of the Commission's General Policy and Interpretations governs 60-day sales or deliveries of natural gas in interstate commerce by non-jurisdictional distribution companies and intrastate pipelines to distribution companies and interstate pipelines in need of temporary emergency gas. Section 157.29 of the Commission's regulations provides that no certificate is required for the sale or transportation of natural gas by independent producers to interstate pipelines for a 60-day period where certain conditions are met. Section 157.22 specifies that no certificate is required for construction and operation of facilities for the sale of natural gas, where such operation or sale is necessary to assure maintenance of adequate natural gas service and will not last longer than 60 days.[8] Generally, these regulations are intended to cover situations where unacceptable levels of natural gas curtailment can be alleviated by 60-day emergency gas transactions.[9]

Surplus natural gas supplies exist which could be made available to make use of electric utilities' alternate fuel capability and to alleviate, in part, the potentially severe effects of the coal shortage. A recent Commission staff survey of the major intrastate pipelines and several large distribution companies indicates that up to 1.0 Bcf of gas per day is currently not being used. Depending upon a number of factors, including weather conditions and storage drawdowns, some of this gas could be made available immediately to the affected utilities for a limited period of time.

NATURE OF THE COMMISSION'S ACTION

The Commission has determined that its Rules and Regulations should be amended to provide an exemption from the certification requirements of section 7 of the Natural Gas Act for certain short term emergency gas transportation and sale arrangements entered into during the current coal emergency. The Commission is taking this action because it finds that the current shortage of coal, and its unavailability for generation of electricity, will imperil the national health and safety, and that this action will contribute to the alleviation of the effects of the coal shortage.

The Commission's finding with respect to the peril to the national health and safety is grounded in part upon the March 9, 1978 determination by Judge Aubrey Robinson of the United States District Court for the District of Columbia, after findings by a board of inquiry appointed by the President, and upon a complaint by the United States with supporting exhibits and affidavits, that the current coal strike, if permitted to continue, would result in such peril and should be enjoined.

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[8] In addition, § 2.79 of the Commission's General Policy and Interpretations provides the Commission's policy for certificating the transportation by interstate pipelines of natural gas sold directly to industrial companies for high priority use. In most instances, coal users would not qualify under this policy.

[9] Moreover, specific references in the regulations to classes of eligible purchasers and the Commission's past interpretation of these regulations may not permit electric utilities to obtain natural gas under the regulations.

Our action here is authorized by section 7(c) of the Natural Gas Act, which provides for emergency exemption from certification requirements. This section has been given a narrow construction. In *Consumer Federation of America* v. *F.P.C.*, 515 F. 2d 347 (D.C. Cir. 1975), the Court recognized that sudden unanticipated demand for natural gas was one of the situations that would justify use of the emergency provision of the Act.[4] We believe the emergency brought on by the coal shortage permits its use.

PROVISIONS OF THE AMENDMENT

The Commission in this action amends its Rules and Regulations to add a new § 157.42 to Part 157, Title 18, CFR, to provide an exemption from the certification requirements of section 7 of the Natural Gas Act for certain short-term emergency gas transportation and sale arrangements entered into during the current coal emergency. The purpose of the amendment is to encourage pipelines and local distribution companies to provide the transportation services necessary to permit qualifying sellers to make up to 60-day emergency sales of natural gas in interstate commerce to eligible electric utilities. Deliveries must commence during the coal emergency period (March 15, 1978, to April 30, 1978) and may not extend beyond May 31, 1978. The amendment will become effective immediately and expires midnight, May 31, 1978.

An exemption under this section, available only to eligible electric utilities as defined in § 157.42(d), would be conditioned upon a determination of eligibility by the Administrator of the Economic Regulatory Administration. The Administrator of ERA can determine that an electric utility (or other person with electric generating capacity) is eligible to purchase emergency gas under this section only if, because of the unavailability of coal, the use by the utility of emergency gas supplies will contribute to alleviating the peril to the national health and safety which attends the continuation of the coal emergency, and in his judgment, will best meet the coal emergency and will serve the public interest. A determination of eligibility by the Administrator is required by § 157.42(c) to be in writing and to be transmitted to the Commission and the requesting parties.

Under the terms of these provisions, the Administrator has broad latitude to exercise his judgment, on the basis of information available to him, to determine which utilities qualify under this section. Electric utilities who wish to purchase gas pursuant to this section should apply to the Administrator of ERA for a determination of eligibility. The application should be addressed to the attention of:

Walter A. Romanek, Director, Division of Coal Utilization, Economic Regulatory Administration, Room 7202, 2000 M Street NW., Washington, D.C. 20461, 202-254-3910.

Paragraph (b) of the new § 157.42 defines other terms used in the section.

"Qualifying seller" is defined as any producer of natural gas which proposes, pursuant to § 157.42, to sell natural gas which is not produced from the Outer Continental Shelf, and the sale or transportation of which had not been previously certificated under the Natural Gas Act. An exception to these limitations is applicable to volumes of gas produced from the Outer Continental Shelf currently being transported under certificates authorizing producer reservation and not otherwise available to the interstate market. In addition, the term includes any intrastate pipeline, local distribution company, or other person (other than an interstate pipeline, or producer of natural gas not otherwise qualified).

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[4] From the onset of natural gas curtailments the Commission has recognized that situations may arise which require the authorization of emergency gas supplies to electric utilities under the extraordinary relief provision of Order No. 467-C (51 FPC 1199), in order to assure continuation of electric power service. See, e.g., *Panhandle Eastern Pipe Line Co.*, Docket No. RP74-31-16 (City of Monroe City, Mo.), order issued January 4, 1974; *El Paso Natural Gas Co.*, Docket No. RP75-42-2 (Community Public Service Commission and City of Lordsburg, N. Mex.), order issued October 3, 1975; *Texas Gas Transmission Corp.*, Docket No. RP75-76-1 (Mississippi Valley Gas Co.), order issued April 30, 1976; *Arkansas Louisiana Gas Co.*, Docket No. RP74-94-3 (City of Winfield, Kans.), order issued October 20, 1976.

"Administrator" is defined as the Administrator of the Economic Regulatory Administration, or other officer or employee of the United States designated by him.

"Coal emergency period" is the period beginning on March 15, 1978, and ending midnight, April 30, 1978.

The terms "interstate pipeline," "intrastate pipeline," and "local distribution company" are also defined.

Paragraph (d) contains the exemption from the certification requirement of section 7 of the Natural Gas Act. It provides that the public interest does not require the issuance of a certificate under section 7 of the Natural Gas Act with respect to the transportation or sale in interstate commerce of natural gas sold by a qualifying seller to an eligible electric utility for delivery commencing during the coal emergency period and ending not later than 60 days after deliveries commence or May 31, 1978, whichever occurs first. It should be noted that the status of otherwise non-jurisdictional sellers, pipelines and local distribution companies under the Natural Gas Act will not be altered by a transaction under this section.

Paragraph (d) also specifies the conditions under which the exemption is applicable, including the following:

(1) Notwithstanding any outstanding Commission order, approved settlement agreement or approved tariff governing transportation services by a transporter (i.e., an interstate pipeline rendering transportation services), the transporter may charge and retain an amount for such transportation up to actual out-of-pocket expenses. Out-of-pocket expenses may include those administrative and general expenses directly associated with transportation services under this section. The purchaser must provide volumes of natural gas to the transporter for compressor fuel and for volumes lost and unaccounted for.

(2) The transportation and sales contracts must authorize the Commission to authorize the transporter, upon request of the transporter or upon its own motion, to purchase the transported gas for system supply if the Commission gives 2 days' notice to the purchaser and determines it is necessary for the public health and safety. A purchase by the transporter would be deemed to be a transaction under 18 CFR 2.68, 157.22 or 157.29. The contract authorization described in this paragraph may be provided by incorporation by reference of the applicable provisions of this regulation.

(3) Transportation under this section shall be subject to interruption by the transporter to the extent that the transporter has inadequate capacity available to maintain service to existing customers. The Commission anticipates that transporters will provide users adequate notice prior to interrupting deliveries under this provision.

(4) Finally, the transporter must comply with certain reporting requirements.

The Commission finds. (1) That the current shortage of coal and its unavailability for generation of electricity will imperil the national health and safety, thereby causing an emergency and permitting the Commission to exercise its exemption authority under section 7(c) of the Natural Gas Act; and that this action which the Commission will reevaluate if its monitoring of the gas supply and storage situation (or the coal supply situation) indicates that such reevaluation is appropriate, will contribute to the alleviation of the effects of the coal shortage;

(2) That because of the emergency caused by the current coal shortage, prior notice and opportunity for comment with respect to this amendment are impracticable, unnecessary and contrary to the public interest;

(3) That this amendment grants an exemption and therefore may be made effective immediately; and

(4) That this amendment is necessary and appropriate for the administration of the Natural Gas Act.

The Commission, acting pursuant to section 7(c) of the Natural Gas Act, 15 U.S.C. 717f(c), the Department of

Energy Organization Act, 42 U.S.C. 7101, et seq., and E.O. 12009, 42 F.R. 46267, *orders:*

(A) Part 157 of Title 18, Code of Federal Regulations, is amended effective immediately and expiring May 31, 1978, by adding a new § 157.42 to read as follows:

§ 157.42 Exemption of certain emergency gas transportation arrangements during the coal emergency period.

(a) *Purpose.* The purpose of this section is to encourage pipelines and local distribution companies to provide such transportation services as are necessary to permit qualifying sellers to make short-term sales of natural gas in interstate commerce to eligible electric utilities during the coal emergency period.

(b) *Definitions.* For purposes of this section—

(1) "Qualifying seller" means

(i) Any producer of natural gas proposing pursuant to this section to sell natural gas—

(A) Which is not produced from the Outer Continental Shelf, and

(B) The sale or transportation of which had not been, immediately before the date on which a contract pursuant to this section was entered into, certificated under the Natural Gas Act,

except for volumes of gas produced from the Outer Continental Shelf currently transported under certificates authorizing producer reservations and not otherwise currently available to the interstate market, or

(ii) Any intrastate pipeline, local distribution company, or other person (other than an interstate pipeline or a producer of natural gas).

(2) "Eligible electric utility" means an electric utility (or other person who has electric generating capacity), with respect to which the Administrator determines that the use of gas purchased pursuant to this section (i) will contribute to alleviating the peril to the national health and safety which attends the continuation of the coal emergency, and (ii) in his judgment (A) will best meet the coal emergency and (B) will serve the public interest.

(3) "Interstate pipeline" means any natural-gas company, as defined in section 2(6) of the Natural Gas Act, which is engaged in the transportation by pipeline of natural gas.

(4) "Intrastate pipeline" means any person (other than an interstate pipeline) engaged in the transportation by pipeline of natural gas.

(5) "Local distribution company" means any person (including a governmental entity) which receives natural gas for local distribution and resale to natural gas users.

(6) "Administator" means the Administrator of the Economic Regulatory Administration, or any officer or employee of the United States designated by him.

(7) "Coal emergency period" means the period beginning on March 15, 1978, and ending midnight, April 30, 1978.

(c) *Determination of eligibility.* Any determination of the Administrator under paragraph (b)(2) of this section shall be in writing and shall be transmitted to the Commission and to the requesting parties.

(d) *Exemption of certain transportation arrangements.* The public interest does not require the issuance of a certificate under section 7 of the Natural Gas Act authorizing the transportation or sale in interstate commerce of natural gas sold by a qualifying seller to an eligible electric utility for delivery commencing during the coal emergency period and ending not later than 60 days after deliveries commence or May 31, 1978, whichever occurs first. Any interstate transportation or sales contract, as appropriate, under this section shall be subject to the following terms and conditions:

(1) Notwithstanding any outstanding Commission order, approved settlement agreement or approved tariff governing transportation services by an interstate pipeline rendering transportation services under this section (hereafter in this section referred to as "transporter"), a transporter may charge and retain an amount for such transportation equal to actual out-of-pocket expenses. Out-of-pocket expenses may include those administrative and general expenses directly associated with such transportation. The purchaser shall provide volumes of natural gas for compressor fuel and for volumes lost and unaccounted for.

(2) Any contract for transportation or sale under this section shall provide that the Commission upon request of the transporter or upon its own motion shall have the authority to authorize the transporter to purchase the transported gas for system supply on those days on which the Commission determines the transporter (or local distribution companies served by the transporter) requires such gas for protection of the public health and safety. The transporter may not purchase the transported gas except upon 2 days' notice by the Commission to the eligible electric utility whose gas is to be purchased. If the transporter purchases gas under this subparagraph, the purchase shall be deemed to be a transaction under 18 CFR 2.68, 157.22 or 157.29, as appropriate.

(3) Transportation pursuant to this section shall be subject to interruption by the transporter to the extent the transporter has inadequate capacity available to maintain adequate service to existing customers.

(4) Within 24 hours after commencement of deliveries pursuant to this section, the transporter shall notify the Commission and the Administrator, by telegram, identifying: (i) the amount of gas to be transported (on a daily basis), (ii) the duration of the transportation, (iii) the date upon which deliveries are to commence, (iv) the seller, (v) the purchaser, (vi) the price of the gas, (vii) the transportation charges and calculations showing their derivation, and (viii) the pipelines participating in the transportation service.

(5) Within 10 days after the termination of deliveries, the transporter shall file with the Commission and the Administrator a sworn statement and four conformed copies thereof setting forth the volume of gas delivered and indicating: (i) the total compensation received by the seller, (ii) the rate schedule applicable to the sale, if any, or, alternatively, the method by which the price per Mcf was derived, (iii) the total amount of compensation received by the transporter (including amounts received for lost or unaccounted for volumes), (iv) the method by which the transporter's compensation was derived, and (v) a detailed description of the end-use of the gas.

(B) The Secretary shall cause prompt publication of this order to be made in the FEDERAL REGISTER.

By the Commission. Commissioner Holden, concurring in part, and dissenting in part, filed a separate statement which is filed as part of the original document.

KENNETH F. PLUMB,
Secretary.

[FR Doc. 78-7391 Filed 3-20-78; 8:45 am]

[¶ 30,009A]

43 F. R. 19354 (May 5, 1978)

[6740-02]

Title 18—Conservation of Power and Water Resources

CHAPTER I—FEDERAL ENERGY REGULATORY COMMISSION DEPARTMENT OF ENERGY

[Docket No. RM77-21; Order No. 6]

PART 141—STATEMENTS AND REPORTS (SCHEDULES)

PART 201—UNIFORM SYSTEM OF ACCOUNTS FOR NATURAL GAS COMPANIES (CLASS A AND CLASS B)

PART 216—UNITS OF PROPERTY FOR USE IN ACCOUNTING FOR ADDITIONS TO AND RETIREMENTS OF GAS PLANT

PART 260—STATEMENTS AND REPORTS (SCHEDULES)

Order Amending the Uniform Systems of Accounts for Natural Gas Companies and Related Regulations To Provide for Base Load Liquefied Natural Gas Facilities

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: By this order, the Commission is adopting amendments to its regulations necessary to provide for the recognition of base load liquefied natural gas facilities. Amendments are also ordered for related report forms. The amendments are being ordered to provide accounting and reporting classifications for base load liquefied natural gas facilities for which no such appropriate classifications existed prior to this order.

EFFECTIVE DATE: January 1, 1978.
FOR FURTHER INFORMATION CONTACT:

M. Wayne McDanal, Office of Chief Accountant, 202-275-4052.

On October 1, 1977, pursuant to the provisions of the Department of Energy Organization Act (DOE Act), Pub. L. 95-91, 91 Stat. 565, approved August 4, 1977 and Executive Order No. 12009, dated September 13, 1977 (42 FR 46267, September 15, 1977), the Federal Power Commission (FPC) ceased to exist and its functions and regulatory responsibilities were transferred to the Secretary of Energy and the Federal Energy Regulatory Commission (FERC) which, as an independent Commission within the Department of Energy, was activated on October 1, 1977.[1]

Before Commissioners: Charles B. Curtis, Chairman; Don S. Smith, Georgiana Sheldon, and Matthew Holden, Jr., and George R. Hall.

Revisions to uniform system of accounts for natural gas companies to provide accounts for base load liquefied natural gas terminaling and processing facilities; order adopting amendments to uniform system of accounts for natural gas companies (Docket No. RM77-21, Order No. 6).

April 28, 1978.

On October 1, 1977, pursuant to the provisions of the Department of Energy Organization Act (DOE Act), Pub. L. 95-91, 91 Stat. 565, approved August 4, 1977 and Executive Order No. 12009, dated September 13, 1977 (42 FR 46267, September 15, 1977), the Federal Power Commission (FPC) ceased to exist and its functions and regulatory responsibilities were transferred to the Secretary of Energy and the Federal Energy Regulatory Commission (FERC) which, as an independent Commission within the Department of Energy, was activated on October 1, 1977.[1]

Section 0.4(h) of part 0 of chapter I, title 18 of the Code of Federal Regulations, which was promulgated by the FERC's order No. 1, docket No. RM78-1, issued October 6, 1977 (42 FR 55450, October 17, 1977), provides that all persons or jurisdictional entities required to file periodic or other reports with any agency or commission whose functions were transferred under the DOE Act to the FERC shall file such reports relating to the transferred functions with the Secretary of the FERC and provides further that the FERC affirms, adopts and continues in effect all previously approved forms as amended herein, for making periodic or other reports.

The "savings provisions" of section 705(b) of the DOE Act provide that proceedings pending before the FPC on the date the DOE Act takes effect shall not be affected and that orders shall be issued in such proceedings as if the DOE Act had not been enacted. All such proceedings shall be continued and further actions shall be taken by the appropriate component of DOE now responsible for the function under the DOE Act and regulations promulgated thereunder. The functions which are the subject of this proceeding were specifically transferred to the FERC by section 402(a)(1) or 402(a)(2) of the DOE Act.

The joint regulation adopted on October 1, 1977, by the Secretary of Energy and the FERC entitled "Transfer of Proceedings to the Secretary of Energy and the Federal Energy Regulatory Commission," 10 CFR part 1000, provided that this proceeding would be continued before the FERC.[2] The FERC takes action in this proceeding in accordance with the above-mentioned authorities.

Pursuant to the notice of proposed rulemaking issued in this docket, the Commission is hereby adopting amendments to its Uniform System of Accounts for Natural Gas Companies (Class A and Class B) to accommodate the accounting for base load liquefied natural gas facilities. The amendments include the adoption of a number of new accounts, including a liquefied natural gas inventory account, plant accounts and the necessary operation and maintenance expense accounts. In addition thereto, two new definitions prompted by this proceeding are being added. The appropriate annual report form changes have also been made.

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[1] The term "Commission" when used in the context of an action taken prior to Oct. 1, 1977, refers to the FPC; when used otherwise, the reference is to the FERC.

[2] 10 CFR 1000.1(d). The joint regulation was published in the Federal Register on Oct. 17, 1977 (42 FR 5534).

On June 8, 1977, the Commission issued a notice of proposed rulemaking in docket No. RM77-21 (42 FR 30846, June 17, 1977). This rulemaking proposed to establish a separate accounting classification for base load liquefied natural gas (LNG) terminaling and processing facilities and to make revisions to FPC form No. 2, Annual Report for Natural Gas Companies, in order to reflect the amended accounting classification.

Comments were invited from interested persons no later than August 8, 1977. In response to the rulemaking notice, the Commission received comments from 11 respondents.[2] In general the responses to the proposed rulemaking were favorable with several of the respondents suggesting modifications to the rulemaking as follows:

The use of five digit account numbers, instead of four digit account numbers presently being used, was objected to by several respondents on the ground that this change would require the reprogramming of existing computer systems entailing significant outlays of funds. The Commission recognizes the respondents' position and has amended the proposal and certain existing account numbers in order to retain the four digit system.

Several respondents suggested that Account 804.2, Liquefied Natural Gas Held for Processing—Net, be repositioned and classified with deliveries and withdrawals from storage. We have adopted this reclassification believing it to be more meaningful, and have divided the account into delivery and withdrawal accounts.

Based upon suggestions from three respondents, we have also added provisions for liquefaction equipment to recognize the possibility of base load liquefaction operations. Numerous other minor revisions also have been incorporated into the accounts and schedules.

Pursuant to the request in the notice in this proceeding, suggested retirement units for the properties classified in the LNG plant accounts were received and have been incorporated in the Units of Property for Use in Accounting for Additions to and Retirements of Gas Plant under part 216 of the Commission's regulations. Comparable lists have also been added for the existing LNG peaking plant accounts.

The Commission is also amending the schedule of the FPC form No. 1 regarding the distribution of salaries and wages. Although prior notice was not provided with respect to the amendment, the change is minor and concerns a schedule which FPC form No. 1 has in common with FPC form No. 2 with respect to which notice was given. The amendment is minor and technical in nature consistent with the purpose of the rulemaking and does not impose additional requirements on reporting entities. Therefore, the Commission believes that prior notice and public procedures are unnecessary.

The Commission finds: (1) The notice and opportunity to participate in this rulemaking proceeding with respect to the matters presently before this Commission; through the submission in writing of data, views, comments, and suggestions; are consistent and in accordance with the procedural requirements prescribed by 5 U. S. C. 553.

(2) The amendments are necessary and appropriate for the administration of the Natural Gas Act.

(3) Because the amendments ordered herein, which were not included in the notice of this proceeding, are consistent with the prime purpose of the proposed rulemaking, further notice thereof and opportunity for comment thereon are unnecessary.

(4) Good cause exists for making the amendments to the Uniform System of Accounts for Natural Gas Companies and to the Units of Property for Use in Accounting for Additions to and Retirements of Gas Plant which are ordered herein effective on January 1, 1978, and the amendments to FPC form No. 1 and form No. 2 which are ordered herein to become effective for the 1978 reporting year.

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[2] Interstate Natural Gas Association of America (INGAA), Public Service Electric & Gas Co., San Diego Gas & Electric Co., Columbia LNG Corp. (late filing), Consolidated Natural Gas Service Co., Michigan Wisconsin Pipe Line Co., Northwest Pipeline Corp., Southern Natural Gas Co., (late filing), Tennessee Gas Pipeline Co., Western LNG Terminal Co., et al., and Public Service Commission of the State of New York.

The Commission orders:[4] (1) Effective January 1, 1978, part 201, the Uniform System of Accounts Prescribed for Natural Gas Companies (Class A and Class B), and part 216, Units of Property for Use in Accounting for Additions to and Retirements of Gas Plant, of subchapter F, chapter I, title 18 of the Code of Federal Regulations are amended to establish separate accounting classifications and retirement units for base load liquefied natural gas plant, all as set forth in the attachment A hereto, which is an integral part of this order.

(2) Effective for the reporting year 1978, applicable schedule pages of FPC form No. 2, Annual Report for Natural Gas Companies (Class A, and Class B), prescribed by § 260.1 of part 260, subchapter G, chapter I, title 18 of the Code of Federal Regulations and the applicable schedule page of FPC form No. 1, Annual Report for Electric Utilities and Licensees (Class A and Class B), prescribed by § 141.1 part 141, subchapter D, chapter I, title 18 of the Code of Federal Regulations are amended, all as set forth in attachment B hereto, which is an integral part of this order.

(3) The Secretary shall cause prompt publication of this order to be made in the FEDERAL REGISTER.

(4) The Secretary shall cause copies of the schedules, as modified by this order, to be transmitted to the Director of the Office of Management and Budget.

By direction of the Commission.

LOIS D. CASHELL,
Acting Secretary.

[¶ 30,009B]

43 F. R. 15417 (April 13, 1978)

[6740-02]

Title 18—Conservation of Power and Water Resources

CHAPTER 1—FEDERAL ENERGY REGULATORY COMMISSION, DEPARTMENT OF ENERGY

[Docket No. Rm 77-17; Order No. 5]

ORDER AMENDING THE UNIFORM SYSTEMS OF ACCOUNTS FOR PUBLIC UTILITIES AND LICENSEES FOR THE PURPOSE OF RECLASSIFYING AMORTIZATION RESERVES

April 5, 1978.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Commission is amending its Uniform systems of Accounts for Public Utilities and Licensees (all classes) for the purpose of reclassifying Account 264—Amortization Reserves-Federal. Amendments are also ordered for related report forms and the regulations prescribing one such report forms. These changes are being made to reflect the true nature of the amortization reserves and also to reflect the intent of Congress in its enactment of the Federal Power Act.

EFFECTIVE DATE: January 1, 1978.

FOR FURTHER INFORMATION CONTACT:

M. Wayne McDanal, Office of Chief Accountant, 202-275-4052.

SUPPLEMENTAL INFORMATION:

On October 1, 1977, pursuant to the provision of the Department of Energy Organization Act (DOE Act Pub. L. 95-91, 91 Stat. 585 (August 4, 1977) and Executive Order No. 12009 42 FR 46267 (September 15, 1977), the Federal Power Commission ceased to exist and its functions and regulatory responsibilities were transferred to the Secretary and the Federal Energy Regulatory Commission (FERC) which, as an independent commission within the Department of Energy, was activated on October 1, 1977.

The "savings provisions" of Section 705(b) of the DOE Act provide that proceedings pending before the FPC on the date the DOE Act takes effect shall not be affected and that orders shall be issued in such proceedings as if the DOE Act had not been enacted. All such proceedings shall be continued and further actions shall be taken by the appropriate component of DOE now responsible for the function under the DOE Act and regulations promulgated thereunder. The functions which are the subject of these proceedings were specifically transferred to the FERC by Delegation Order No. 0204-1 of the Department of Energy pursuant to Section 642 and 402(e) of the DOE Act.

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[4] The Commission is acting under authority pursuant to the provisions of the Federal Power Act as amended, particular secs. 301, 302, 304, 309, and 311; (49 Stat. 838, 854, 855, 858. 859: 16 U. S. C. 796, 825, 825a, 825c, 825h, and 825j) and the provisions of the Natural Gas Act, as amended, particularly secs. 8, 9, 10, and 16 (52 Stat. 825-826, 1830, 15 U. S. C. 717g, 717h, 717 l and 717 o).

The joint regulations adopted on October 1, 1977, by the Secretary and the FERC entitled "Transfer of Proceedings to the Secretary of Energy and the FERC, 10 CFR —; *Provided*, That this proceeding would be continued before the FERC. The FERC takes action in this proceeding in accordance with the above mentioned authorities.

On April 8, 1977, the Federal Power Commission issued a Notice of Proposed Rulemaking in Docket No. RM77-17 (42 FR 20303, April 19, 1977). This rulemaking proposed to amend the Uniform Systems of Accounts and related report forms for Public Utilities and Licensees (All Classes), the regulations prescribing one of such report forms; FPC Report Form No. 2, Annual Report for Natural Gas Companies (Class A and Class B); and FPC Report Form No. 2-A, Annual Report for Natural Gas Companies (Class C and Class D) for the purpose of reclassifying Account 264, Amortization Reserve—Federal.

Comments were invited from interested persons on or before May 13, 1977. Due to a request, this date was extended to June 1, 1977. Comments were received from 14 respondents. The List of Respondents is designated as Attachment A hereto.

The majority of the respondents supported the proposed rulemaking, however, many of these respondents suggested modification to the proposal. The most numerous comments received expressed concern over the FPC's proposal to retitle Account 264. Amortization Reserve—Federal, as Account 215.1, Appropriated Retained Earnings—Amortization Reserve, Federal. The majority of the respondents believe that the term "segregated" or "restricted" is preferable to the proposed term "appropriated."

The term "appropriated retained earnings indicates that an equivalent amount in assets is not to be paid out in dividends which conveys the intent of Congress in establishing these reserves. For this reason and the fact that the term "appropriated" is consistent with the wording of Section 3(13) of the Federal Power Act (Act), we do not believe that the term should be modified.

Two respondents disagreed with the proposed accounting changes and recommended that the present accounting for the reserves be maintained. One respondent suggested that the proposed accounting would violate the "clean surplus" concept. Another respondent stated that excess earnings should not be used in the computation of debt service coverage and included in the equity portion of a utility's capital structure.

We do not agree with the respondents' comments. The "clean surplus" concept holds that all items of profit and loss are to enter into the determination of net income. The transfer of amounts from unappropriated to appropriated retained earnings does not violate the concept. Earnings required to be set aside by licensees under Section 10(d) of the Act are earnings in excess of the specified return in hydroelectric project licenses. To what extent, if any, earnings set aside may be considered as excess earnings is a matter to be determined through recapture proceedings under Section 14 of the Act, or in other proceedings before the Commission. The reclassification of these amounts from the appropriated retained earnings classification is without prejudice to treatment of these amounts in future proceedings before the Commission.

The Commission finds (1) The notice and opportunity to participate in this rulemaking proceeding with respect to the matters presently before the Commission through submission, in writing, of data, views, comments, and suggestions in the manner as described above are consistent and in accordance with the procedural requirements prescribed by 5 U. S. C. 553.

(2) The amendments to the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act, Parts 101 and 104, Subchapter C, to § 141.13, Part 141, Subchapter D, and to FPC Forms No. 1, No. 1-F, and No. 9 prescribed by §§ 141.2, and 141.13, Part 141, Subchapter D, all in Chapter I, Title 18 of the Code of Federal Regulations, herein adopted, are necessary and appropriate

[The next page is 30,055-7.]

for the Administration of the Federal Power Act.

(3) The amendments to FPC Forms No. 2 and No. 2-A prescribed by §§ 260.1 and 260.2, Part 260, Subchapter G, in Chapter I, Title 18 of the Code of Federal Regulations herein adopted, are necessary and appropriate for the administration of the Natural Gas Act.

(4) The reclassification and amendments, herein adopted, are necessary to reflect the true nature of the amortization reserves and the intent of Congress in its enactment of the Federal Power Act.

(5) The action taken herein is without prejudice to treatment of the amounts reordered in Account 215.1, Appropriated Retained Earnings—Amortization Reserve—Federal, in future proceedings before the Commission.

(6) Good cause exists for making the amendments to FPC Forms No. 1, No. 1-F, No. 2, No. 2-A, and No. 9, herein adopted, effective for the reporting year 1978.

(7) Good cause exists for making the amendments to the Uniform System of Accounts for Public Utilities and Licensees and to the regulations prescribing FPC Form No. 9 herein adopted, effective January 1, 1978.

The Commission, acting pursuant to the provisions of the Federal Power Act, as amended, particularly Sections 10(d), 301(a) 302(b), 304(a), 309 and 311 thereof (41 Stat. 1069, 49 Stat. 843, 82 Stat. 617, 49 Stat. 854, 855, 858, 859; 16 U. S. C. 803(d), 825(a), 825a(b), 825c (a), 825h, 825(j), and the provisions of the Natural Gas Act, as amended, particularly Sections 10(a) and 16 thereof (52 Stat. 826, 830; 15 U. S. C. 7171(a) 717(o), orders:

[¶ 30,010]

43 F. R. 20789 (May 15, 1978)

[Docket No. RM78-13]

PART 1—RULES OF PRACTICE AND PROCEDURE

PART 3—ORGANIZATION; OPERATION; INFORMATION AND REQUESTS

Order Permitting Recording and Photographing of Open Commission Meetings

MAY 9, 1978.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: This rule amends the Federal Energy Regulatory Commission's (Commission) regulations under the Government in the Sunshine Act to allow public observers at the Commission's open meetings to use tape recorders and other recording equipment and cameras without lighting aids. Restrictions in the regulations are designed so that this type of activity will not interfere with the orderly conduct of Commission meetings.

EFFECTIVE DATE: May 9, 1978.

FOR FURTHER INFORMATION CONTACT:

Lois Cashell, Assistant Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, 202-275-4166.

SUPPLEMENTARY INFORMATION: On March 11, 1977, in Order No. 562, the Federal Power Commission (FPC) issued regulations to conform its open meeting procedures to the requirements of section 3 of the Government in the Sunshine Act, 5 U.S.C. 552b. The regulations invited the public to observe and listen to meetings, but not to participate or "record any of the discussions by means of electronic or other devices or cameras." (18 CFR 1.3a (b)(1)). Under section 705(a) of the Department of Energy Organization Act, (Pub. L. No. 95-91, 91 Stat. 565, 605) and Order No. 1, issued by the Federal Energy Regulatory Commission (FERC) on October 6, 1978, those regulations apply to meetings of the FERC.

In declining to allow such recording, the FPC cited the logistical difficulties involved and the potential for disruption, stating that ample provision is made for members of the press desiring to report on open meetings. The Federal Energy Regulatory Commission by this order amends its regulations to allow the use of tape recorders and other recording equipment and still and movie cameras without lighting aids. The Commission believes that these amendments are in the public interest by enhancing the opportunity for public observation of the decision-making process. Through the procedures established by this order, the Commission believes that this type of activity will not interfere with the orderly conduct of its meetings.

The Commission stresses that the expanded right to observe Commission meetings (and the possibility of obtaining transcripts or recordings of discussion at closed meetings) should not be viewed as creating new grounds for challenging the basis and rationale for Commission action. Observations made by individual members of the Commission during the course of deliberations may not necessarily reflect the reasoning underlying the Commission's final action on a given matter. Thus, the legal sufficiency of Commission action must, as in the past, be judged solely on the basis of the action itself and any official supporting statement released by the Commission—not on the basis of remarks or observations made prior thereto.

The Commission finds: (1) The amendments prescribed herein concern matters of agency organization and procedure which do not require notice or hearing under 5 U.S.C. 553.

(2) In view of the purpose, intent and effect of the amendments herein ordered, good cause exists for making them effective upon issuance of this order.

(3) It is appropriate and in the public interest in administering the Federal Power Act, the Natural Gas Act and the Department of Energy Organization Act to adopt the amendments hereinafter set forth.

The Commission, acting pursuant to the provisions of the Federal Power Act, as amended, particularly sections 308 and 309 (49 Stat. 858, 859; 16 U.S.C. 825g, 825h), the provisions of the Natural Gas Act, particularly sections 15 and 16 (52 Stat. 829, 830; 15 U.S.C. 717n, 717o), and the provisions of the Department of Energy Organization Act, particularly sections 401, 402, and 403 (91 Stat. 582-585), *orders*:

(A) Part 1, Subchapter A, Chapter I, Title 18 of the Code of Federal Regulations is amended as set forth below:

Section 1.3a is amended in paragraph (b) by revising the third sentence of subparagraph (1) by redesignating subparagraph (2) as subparagraph (4) and by inserting new subparagraphs (2) and (3) to read as follows:

§ 1.3a Notice and procedures for Commission meetings.

* * * * *

(b) Open meetings. (1) * * * The public is invited to observe and listen to the meeting but not to participate. * * *

(2) The recording of discussions at Commission meetings by means of electronic or other devices (including tape recorders, stenotype, stenomask, or shorthand) and the photographing of Commission meetings by still and movie cameras, without lighting aids, is permitted. The Commission reserves the right to suspend the operation of this part of its regulations with respect to the consideration of a particular item on its agenda upon the motion of a member of the Commission and the affirmative vote of the Commission.

(i) Due to the limited space of the Commission meeting room, use of recording or photographic equipment which would require the user to move about the room during the meeting is not allowed. Recording and photographic equipment may be set up and used only in the public areas of the Commission meeting room as designated by the Commission.

(ii) Except for portable equipment which is used at an individual's seat in the audience, equipment must be in place and ready to use prior to the start of the meeting or set up during a recess of the meeting. Such equipment may be removed only at the conclusion of the meeting or during a recess. A pre-arranged recess for the set up or removal of equipment may be requested through the Commission's Director of Public Information.

(iii) No microphones may be placed on the tables used by the Commissioners and Staff.

(iv) Any deviation from the regulations in subparagraph (2) will require a waiver of the rules by the Commission.

(3) Transcripts of Commission meetings are not part of the "formal record" as defined in section 1.1(19) of this Part nor the "public records" of the Commission as defined in § 1.36(c)(2) of this Part.

(4) * * *

* * * * *

(B) Part 3, Subchapter A, Chapter I, Title 18 of the Code of Federal Regulations is amended as set forth below:

Section 3.8 is amended in paragraph (j) by deleting the "." at the end of subparagraph (4) and inserting in lieu thereof a ";" and new subparagraph (5) to read as follows:

§ 3.8 Public information and submittals.

* * * * *

(j) * * *; (5) regulations pertaining to the use of television, movie and still cameras and recording equipment in connection with the Commission's open public meetings under the Government in the Sunshine Act are found in Section 1.3a of this Chapter.

(C) The amendments adopted herein shall be effective upon issuance of this order.

(D) The Secretary shall cause prompt publication of this order to be made in the FEDERAL REGISTER.

By the Commission.

KENNETH F. PLUMB,
Secretary.

[FR Doc. 78-13078 Filed 5-12-78; 8:45 am]

[¶ 30,011]

43 F. R. 23564 (May 31, 1978)

[Docket No. R-441; Order No. 455-C]

PART 2—GENERAL POLICY AND INTERPRETATIONS

Further Amendment of Statement of Policy Relating to Optional Procedure for Certificating New Producer Sales of Natural Gas

MAY 19, 1978.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rulemaking.

SUMMARY: The Commission extends the 9-month period of review during which deliveries are made at the prevailing nationwide ceiling rate until a final order has been issued determining the contract rate just and reasonable. If the rate determined by the Commission is higher than the nationwide rate collected, the final order will allow a surcharge to be collected for the difference in rates during the extended period. The purpose of this rulemaking is to provide consumers with the protection intended by the Natural Gas Act.

EFFECTIVE DATE: May 19, 1978.

FOR FURTHER INFORMATION CONTACT:

Elisabeth Pendley, Office of the General Counsel, Federal Energy Regulatory Commission, 202-275-4216.

SUPPLEMENTARY INFORMATION: Pursuant to 5 U.S.C. 553, sections 4, 5, 7, 8, 14, 15, and 16 of the Natural Gas Act (52 Stat. 822, 823, 824, 825, 828, 829, 830; 15 U.S.C. 717c, 717d, 717f, 717g, 717m, 717n, 717o), and pursuant to section 403(a) of the DOE Act (91 Stat. 565), the Commission issues an amendment to the: General Rules under the Natural Gas Act, Subchapter A, Chapter I, Title 18, CFR.

The Commission's optional certificate procedure was established by Order No. 455, Optional Procedure for Certificating New Producer Sales of Natural Gas, 48 F.P.C. 218 (1972), affirmed in part and reversed in part sub nom., *Moss* v. *F.P.C.*, 502 F.2d 461 (D.C. Ctr. 1974), reversed in part, 424 U.S. 494 (1976). Originally § 2.75 of the regulation, which implemented Order No. 455, contained, in paragraph (o), a provision which permitted producers to collect their contract rate without any refund obligation 6 months after the commencement of deliveries[1] until such time as the Commission entered a final order on the application. This provision was operative despite the possibility that the Commission might ultimately conclude that the contract rate was in excess of the just and reasonable rate for the sale of the gas.

After 2 years of experience under Order No. 455, the Commission, in Order No. 455-B, issued November 25, 1974, concluded that the 6-month period within which to analyse the optional pricing applications was inadequate. The Commission increased the time period for analysis to 9 months, stating:

> that the "public interest requires a disposition of the certificate applications under the optional procedure for certificating new producer sales of natural gas, prior to the effectuation of a non-refundable contract rate. Accordingly the Commission finds that the extension of the time period from six to nine months is justly warranted and compelled by the public interest." (52 FPC 1418)

The change did not however, prevent producers from collecting the contract rate, without refund obligation, after the 9-month period, if the Commission had not yet been able to issue a final order.

Recent applications under the optional pricing alternative have proven to be extremely complex, multiblock ventures which require significant time by staff to properly and completely analyze. Often additional information from the applicant is required. It is our experience that the production of such additional information is often not made in a timely manner in order to enable the Commission to complete its analysis within the 9-month period. Additionally, the applications, particularly in the complicated multiblock cases, are usually contested. The result is that the applications are set for hearing, and the administrative process requires substantially more time than the 9-month period originally anticipated to be adequate.

The consequences of allowing producers to automatically collect their contract rate following the expiration of the 9-month period have become much more severe in their effect on consumers. We note that in certain recent cases producers have sought to collect rates of $2.54 and $3.30. Other applications before the Commission indicate that the price levels sought are also substantially in excess of the nationwide just and reasonable rate.[2] Typically, the optional price gas is sold from offshore blocks, and involve large reserves. In many of the cases the Commission cannot, due to factors noted above, reach a final decision in the 9-month period. Accordingly the contract rate goes into effect without refund obligation. The effect on consumers is immediate and substantial. Under the present § 2.75(o) there does not appear to be a satisfactory method for indemnifying consumers for portions of the rate which might ultimately be determined to be in excess of the just and reasonable rate.

The Commission cannot permit consumers to go unprotected during the period of analysis and administrative proceedings necessary to determine the public interest and the necessity of allowing sales of gas at prices substantially in excess of the nationwide norm.

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[1] In its May 8, 1978 order in *Pennzoil Louisiana and Texas Offshore Company, Inc., et al.*, Docket Nos. CI77-702, et al., the Commission found that the applicable time period before the applicants were permitted to collect the contract rate ran from the date the Commission was notified of commencement of deliveries as required by § 2.75(n).

[2] In *Pennzoil Louisiana and Texas Offshore Company Inc.*, Docket No. CI78-767, the applicants have sought a rate of $4.74 plus $0.06 per Mcf compression charge, Btu adjustment and tax reimbursements for its interest in 50 offshore blocks.

Conversely, where Commission proceedings are quite extended it appears inequitable to require producers to sell at the national rate for excessive periods of time where the just and reasonable rate is ultimately determined to be in excess of the national rate.

Accordingly the Commission amends paragraph (o) of § 2.75 to permit it, in appropriate cases, to extend the time for consideration of applications filed under § 2.75. The right of the producer to sell at the prevailing nationwide ceiling rate for 9 months is preserved. However, if the Commission determines that it will be unable to complete the proceeding within the 9-month period, the Commission may issue an order extending the time for its consideration of the application. If the Commission extends the 9-month period, the producer is required to continue sales at the nationwide ceiling rate for the period of the extension.

Upon issuance of a final order by the Commission which finds that the just and reasonable rate is in excess of the nationwide prevailing rate, the Commission, if it extended the 9-month period, will permit the producer to recoup the portion of such excess that accrued during the period of any extension ordered by the Commission. More specifically the total surcharge will be an amount equal to the difference between the rate collected by the producer during the extension period, and the rate the Commission ultimately finds to be just and reasonable, plus the applicable interest rate on refunds. The surcharge may be collected in a manner and over a period of time prescribed by the Commission in its final order on the application.

If the Commission does not extend the 9-month period, the present procedure under § 2.75(o) would remain applicable.

The Commission is making this amendment effective with respect to applications filed after the date of issuance of this order upon a finding that good cause exists to proceed without compliance with the notice, public procedure, and effective date provisions of 5 U.S.C. 553. The Commission is concerned that a delay in the effective date of this rule until after public comment would trigger a flood of applications during the comment period from producers wishing to collect contract rates after the 9-month period without refund obligation. Such a result would defeat the Commission' purpose of protecting consumers from the economic burden of non-refundable rate collections in excess of the just and reasonable rate and could so overwhelm the Commission with § 2.75 applications that existing as well as new applications could not be processed within the 9-month period. For these reasons, the Commission has found it necessary to make this amendment effective with respect to § 2.75 filings made after the date of issuance of this order.

The Commission finds. (1) Good cause exists to proceed without compliance with the notice, public procedure and effective date provisions of 5 U.S.C. 553. It is contrary to the public interest in this particular case to provide for notice where we seek to protect consumers against the collection by producers of rates in excess of the national ceiling rate, without refund obligation. Any delay in the issuance and effectiveness of this order will delay the protection consumers are required to receive under the Natural Gas Act.

(2) The Amendment of Part 2, General rules of practice and procedure, General Policy and Interpretations, Subchapter A, Chapter I, Title 18 of the Code of Federal Regulations, § 2.75(o) Optional Procedure For Certificating New Producer Sales of Natural Gas, as herein prescribed, is necessary and appropriate for the Administration of the Natural Gas Act.

(3) In view of the purpose, intent and effect of the amendment herein ordered, good cause exists for making it effective upon issuance of this order.

Acting pursuant to the provisions of the Natural Gas Act, as amended, particularly sections 4, 5, 7 and 16 thereof (52 Stat. 822, 823, 824, 825 and 830; 15 U.S.C. 717c, 717d, 717f, and 717o) and pursuant to Section 403 (a) of the DOE Act (91 Stat. 565).

The Commission orders. (A) Part 2 of the Commission's General Rules of Practice and Procedure, General Policy and Interpretations, Subchapter A, Chapter I, Title 18 of the Code of Federal Regulations is amended by revising § 2.75(o) as follows:

§ 2.75 Optional procedure for certificating new producer sales of natural gas.

* * * * *

(o)(1) If the parties elect to commence deliveries as set forth in paragraph (n) of this section, such deliveries will be made at rates no higher than the prevailing nationwide ceiling rate and shall so continue for 9 months.

(2) If the Commission determines that it will not be able before the expiration of the 9-month period to issue its final order, it may issue an order extending the 9-month period until such final order is issued. Deliveries during the period of the extension will continue to be made at rates no higher than the prevailing nationwide rate.

(3) If the final Commission order establishes a just and reasonable rate in excess of the prevailing nationwide rate which was charged during the period of any extension under paragraph (o)(2) of this section, the applicant may recoup by means of a surcharge the excess of (1) the amount which would have been collected had such just and reasonable rate been in effect during such period over (2) the amount actually collected during such period, plus interest on such excess. The surcharge shall be collected over such period and in such manner as the Commission prescribes in its final order.

(4) If the Commission does not extend the 9-month period in the accordance with paragraph (o)(2) of this section, then at the end of such 9-month period (if the Commission has not made its final order), the seller upon the filing of a notice of change in rate pursuant to § 154.94 of this chapter of the Commission's regulations shall be entitled to receive without refund obligation and the purchaser shall be entitled to pay, the rates specified in the contract initially filed, and such contract rates shall continue as the effective rates until the Commission enters its final order on the certificate application.

(B) This amendment provided for herein is effective on date of issuance, and shall apply to all applications filed after the date of issuance of this order.

(C) The Secretary of the Commission shall cause prompt publication of this order to be made in the FEDERAL REGISTER.

By the Commission.

KENNETH F. PLUMB,
Secretary.

[FR Doc. 78-15089 Filed 5-30-78; 8:45 am]

[¶ 30,012]

43 F. R. 27174 (June 23, 1978)

SUBCHAPTER A—GENERAL RULES

[Docket No. RM78-15]

PART 1b—RULES RELATING TO INVESTIGATIONS

Establishment, Final Rule

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: This amendment to the regulations of the Federal Energy Regulatory Commission (Commission) sets forth the Commission's policy and procedures relating to investigations of persons and matters subject to its jurisdiction. The regulations adopted today are intended to state clearly the Commission's policy and procedures for investigations conducted under the statutes it administers.

EFFECTIVE DATE: June 14, 1978.

FOR FURTHER INFORMATION CONTACT:

Thomson vonStein, 825 North Capitol Street, Washington, D.C. 20426, 202-275-1832.

BACKGROUND: Notice is hereby given that the Federal Energy Regulatory Commission (the Commission) is amending Subchapter A of Title 18, Code of Federal Regulations, by establishing a new Part 1b, Rules Relating to Investigations, effective immediately.

The Commission has broad authority to investigate matters subject to its jurisdiction. Sections 5(b), 6(a), and 14 of the Natural Gas Act, Sections 206(b), 208(a) and 307, of the Federal Power Act, and Section 12 of the Interstate Commerce Act all authorize the Commission to investigate matters and persons subject to its jurisdiction. For example, Sections 14(a) of the Natural Gas Act and 307(a) of the Federal Power Act broadly authorize the Commission to—

> * * * investigate any acts, conditions, practices, or matters which it may find necessary or proper in order to determine whether any person has violated or is about to violate any provisions of this Act or any rule, regulation, or order thereunder, or to aid in the enforcement of the provisions of this Act or in prescribing rules or regulations thereunder, or in obtaining information to serve as a basis for recommending further legislation.

In addition, Section 12(1) of the Interstate Commerce Act, gives this Commission the authority to "inquire into and report on the management of the business of all (oil pipelines) subject to the provisions of this chapter." This authority was transferred to this Commission by the establishment of the Department of Energy.

The Commission has not previously promulgated a set of regulations specifically designed to cover investigations. Rather, it has generally conducted investigations pursuant to its statutory authority on an ad hoc basis and where appropriate to applicable provisions of its rules of practice and procedure. The regulations adopted today are intended to state clearly the Commission's policy and procedures for investigations conducted under the statutes it administers.

These regulations, which are summarized below, are similar to rules relating to investigations used by other Federal agencies with regulatory mandates similar to those of the Commission. Regulations used by those agencies have been in use for a number of years, and are promulgated under statutory authority similar to that provided by the statutes administered by the Commission.

SUMMARY OF PART 1b

Section 1b.1 of Part 1b defines certain terms used in Part 1b.

Section 1b.2 states that the rules apply only to investigations and not adjudicative proceedings.

Section 1b.3 states the Commission may investigate any matters subject to its jurisdiction, which investigative authority is set out in Sections 206, 208, and 307 of the Federal Power Act, Sections 5, 6, and 14 of the Natural Gas Act and Section 12 of the Interstate Commerce Act.

Section 1b.4 provides that the Commission may, in its discretion, conduct either preliminary or formal investigations, which may be private or public. This formalizes established Commission policy, and provides for private investigations, which are appropriate in certain situations, such as when evidence of possible violations or knowing and willful violations, if made public before the investigation is complete or other action is taken, may prejudice the rights of witnesses or potential defendants, or may delay the investigation.

Section 1b.5 states that the Commission has the discretion to order a formal investigation, in which case it issues an Order of Investigation which will outline the basis for the investigation, the matters to be investigated, names the officer(s) who will have the authority to conduct the investigation, and their authority. The particular authority of officers conducting an investigation is derived from Section 307 of the Federal Power Act, Section 14 of the Natural Gas Act and Section 12 of the Interstate Commerce Act.

Formal investigations are appropriate when preliminary investigations indicate that compulsory process may be necessary to obtain information.

Section 1b.6 states that the Commission or its staff may, in its discretion, conduct preliminary investigations without formal order of the Commission. If a preliminary investigation indicates a need for a formal investigation or if compulsory process is required, the Commission may then initiate a formal investigation.

Section 1b.7 states that when it appears there has been a violation or may be a violation of the statutes administered by the Commission, or of the Commission's rules or orders, the Commission may take various actions including instituting administrative proceedings, seeking an injunction, or referring the matter to another governmental authority.

Section 1b.8 makes clear that anyone may request an investigation and that there are no formalities for such requests. This is designed to encourage as wide as possible a flow of information to the Commission from the public about matters it is concerned with. It is similar to § 1.6 of the rules of practice and procedure which concerns complaints. The requirements for requesting an investigation, however, are less formal than those for filing a complaint.

Section 1b.9 states that, unless otherwise made public by the Commission, or unless made public under the Freedom of Information Act, all information or documents obtained by the Commission in the course of an investigation shall not generally be available to the public.

Section 1b.10 describes the particular officers who may conduct a formal investigation.

Section 1b.11 distinguishes between the rights of intervenors or parties in adjudicative administrative proceedings and investigations where there are no respondents or parties as such. Administrative investigations have long been held not to require the full panoply of judicial procedures such as the right to participate and cross-examine. "Hannah v. Larch" 363 U.S. 420 (1960).

Section 1b.12 provides that only an official reporter may transcribe testimony given in an investigation and provides that witnesses may obtain copies of their testimony unless the director of the Office responsible for the investigation for good cause determines that they may not. In any case, witnesses may inspect their testimony. This supersedes § 1.21(b) of the rules of practice and procedure for purposes of Part 1b.

Section 1b.13 describes the particular actions which officers conducting formal investigations may take and parallels Section 14(b) of the Natural Gas Act and Section 307(b) of the Federal Power Act.

Section 1b.14(a) describes how subpoenas may be served. Section 1b.14 (b) and (c) establishes procedures to encourage compliance with subpoenas by requiring a subpoenaed party to explain why any subpoenaed documents were not produced in compliance with the subpoena and requires documents withheld under claim of attorney-client privilege to be listed so that the validity of the claim can be verified.

Section 1b.15 states that the Commission may enforce its subpoenas if necessary and that criminal penalties may also be used to enforce subpoenas.

Section 1b.16(a) states that on request witnesses must be shown the Commission's Order of Investigation and, if appropriate, may be furnished a copy of such order. Section 1b.16(b) states that persons giving evidence in an investigation may be represented by counsel but establishes procedures for disclosing possible conflicts of interest of attorneys who represent more than one person involved in an investigation. Section 1b.16(c) regulates the conduct of witnesses and counsel at hearings. It provides that witnesses may, at their discretion, make any statement they wish at the end of an investigative hearing.

Section 1b.17 makes the Commission's rule of practice relating to the representation and conduct of attorneys applicable to investigations.

Section 1b.18 states that persons involved in an investigation may submit any statement they wish during an investigation.

Section 1b.19 sets up a procedure whereby defendants in potential injunctive proceedings may, where appropriate in the interest of the proper administration of the law, be given the right to have their position presented to the Commission whenever the office responsible for the investigation recommends an enforcement action against such persons.

Finally, § 1b.20 deals with requests for confidential treatment of information furnished to the Commission in an investigation.

EFFECTIVE DATE

The Commission makes these regulations effective without prior notice and public procedure. Because they are interpretative rules, statements of policy and rules of agency procedure and practice, notice and public procedure thereon are not required under applicable administrative requirements, and the Commission considers it unnecessary to defer implementation awaiting public comment.

Although the Commission is making these regulations effective immediately, we welcome interested parties to submit comments or suggestions with respect to the regulations. The Commission will evaluate any information received and will consider appropriate revisions to the regulations. An original and 14 copies should be filed by July 24, 1978, with the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE, Washington, D.C. 20426. All comments should reference Docket No. RM78-15.

For the foregoing reasons, Subchapter A of Title 18, Code of Federal Regulations, is amended as set forth below, effective immediately.

By the Commission.

KENNETH F. PLUMB,
Secretary.

1. Subchapter A of Title 18, Code of Federal Regulations, is amended by adding a new Part 1b, to read as follows:

Sec.
1b.1 Definitions.
1b.2 Scope.
1b.3 Scope of investigations.
1b.4 Types of investigations.
1b.5 Formal investigations.
1b.6 Preliminary investigations.
1b.7 Procedure after investigation.
1b.8 Requests for Commission investigations.
1b.9 Confidentiality of investigations.
1b.10 By whom conducted.
1b.11 Limitation on participation.
1b.12 Transcripts.
1b.13 Powers of persons conducting formal investigations.
1b.14 Subpoenas.
1b.15 Non-compliance with compulsory processes.
1b.16 Rights of witnesses.
1b.17 Appearance and practice before the Commission.
1b.18 Right to submit statements.
1b.19 Submissions.
1b.20 Request for confidential treatment.

AUTHORITY: Natural Gas Act, 15 U.S.C. 717 *et seq.*, Federal Power Act, 16 U.S.C. 792 *et seq.*, Interstate Commerce Act, 49 U.S.C. § 1 *et seq.*, Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267.

§ 1b.1 Definitions.

For purposes of this part—

(a) "Formal investigation" means an investigation instituted by a Commission Order of Investigation.

(b) "Preliminary Investigation" means an inquiry conducted by the Commission or its staff, other than a formal investigation.

(c) Investigating officer means the individual(s) designated by the Commission in an Order of Investigation as Officer(s) of the Commission.

§ 1b.2 Scope.

This part applies to investigations conducted by the Commission but does not apply to adjudicative proceedings.

§ 1b.3 Scope of investigations.

The Commission may conduct investigations relating to any matter subject to its jurisdiction.

§ 1b.4 Types of investigations.

Investigations may be formal or preliminary, and public or private.

§ 1b.5 Formal investigations.

The Commission may, in its discretion, initiate a formal investigation by issuing an Order of Investigation. Orders of Investigation will outline the basis for the investigation, the matters to be investigated, the officer(s) designated to conduct the investigation and their authority. The director of the office responsible for the investigation may add or delete Investigating Officers in the Order of Investigation.

§ 1b.6 Preliminary investigations.

The Commission or its staff may, in its discretion, initiate a preliminary investigation. In such investigations, no process is issued or testimony compelled. Where it appears from the preliminary investigation that a formal investigation is appropriate, the staff will so recommend to the Commission.

§ 1b.7 Procedure after investigation.

Where it appears that there has been or may be a violation of any of the provisions of the acts administered by the Commission or the rules, opinions or orders thereunder, the Commission may institute administrative proceedings, initiate injunctive proceedings in the courts, refer matters, where appropriate, to the other governmental authorities, or take other appropriate action.

§ 1b.8 Requests for Commission investigations.

(a) Any individual, partnership, corporation, association, organization, or other Federal or State governmental entity, may request the Commission to institute an investigation.

(b) Requests for investigations should set forth the alleged violation of law with supporting documentation and information as completely as possible. No particular forms or formal procedures are requested.

(c) It is the Commission's policy not to disclose the name of the person or entity requesting an investigation except as required by law, or where such disclosure will aid the investigation.

§ 1b.9 Confidentiality of investigations.

All information and documents obtained during the course of an investigation, whether or not obained pursuant to subpoena, and all investigative proceedings shall be treated as nonpublic by the Commission and its staff exept to the extent that (a) the Commission directs or authorizes the public disclosure of the investigation; (b) the information or documents are made a matter of public record during the course of an adjudicatory proceeding; or (c) disclosure is required by the Freedom of Information Act, 5 U.S.C. 552. Procedures by which persons submitting information to the Commission during the course of an investigation may specifically seek confidential treatment of information for purposes of Freedom of Information Act disclosure are set forth in 18 CFR Part 3b and § 1b.20. A request for confidential treatment of information for purposes of Freedom of Information Act disclosure shall not, however, prevent disclosure for law enforcement purposes or when disclosure is otherwise found appropriate in the public interest and permitted by law.

§ 1b.10 By whom conducted.

Formal Commission investigations are conducted by the Commission or by an individual(s) designated and authorized in the Order of Investigation. Investigating Officers are "officers" within the meaning of the statutes administered by the Commission and are authorized to perform the duties of their office in accordance with the laws of the United States and the regulations of the Commission. Investigating Officers shall have such duties as the Commission may specify in an Order of Investigation.

§ 1b.11 Limitation on participation.

There are no parties, as that term is used in adjudicative proceedings, in an investigation under this Part and no person may intervene or participate as a matter of right in any investigation under this part. Section 2.72 of the rules is specifically not applicable to private investigations conducted by the Commission or its staff.

§ 1b.12 Transcripts.

Transcripts, if any, of investigative testimony shall be recorded solely by the official reporter, or by any other person or means designated by the investigating officer. A witness who has given testimony in an investigation shall be entitled, upon written request, to procure a transcript of the witness' own testimony on payment of the appropriate fees, except that in a nonpublic formal investigation, the office responsible for the investigation may for good cause deny such request. In any event, any witness or his counsel, upon proper identification, shall have the right to inspect the official transcript of the witness' own testimony. This provision supersedes § 1.21(b) of the rules of practice.

§ 1b.13 Powers of persons conducting formal investigations.

Any member of the Commission or the Investigating Officer, in connection with any formal investigation ordered by the Commission, may administer oaths and affirmations, subpoena witnesses, compel their attendance, take evidence, and require the production of any books, papers, correspondence, memoranda, contracts, agreements or other records relevant or material to the investigation.

§ 1b.14 Subpoenas.

(a) Service of a subpoena upon a person named therein shall be made be the investigating officer (1) by personal delivery, (2) by certified mail, (3) by leaving a copy thereof at the principle office or place of business of the person to be served, (4) or by delivery to any person designated as agent for service or the person's attorney.

(b) At the time for producing documents subpoenaed in an investigation, the subpoenaed party shall submit a statement stating that, if true, such person has made a diligent search for the subpoenaed documents and is producing all the documents called for by the subpoena. If any subpoenaed document(s) are not produced for any reason, the subpoenaed party shall state the reason therefor.

(c) If any subpoenaed documents in an investigation are withheld because of a claim of the attorney-client privilege, the subpoenaed party shall submit a list of such documents which shall, for each document, identify the attorney involved, the client involved, the date of the document, the person(s) shown on the document to have prepared and/or sent the document, and the person(s) shown on the document to have received copies of the document.

§ 1b.15 Non-compliance with compulsory processes.

In cases of failure to comply with Commission compulsory processes, appropriate action may be initiated by the Commission or the Attorney General, including but not limited to actions for enforcement or the imposition of penalties.

§ 1b.16 Rights of witnesses.

(a) Any person who is compelled or requested to furnish documentary evidence or testimony in a formal investigation shall, upon request, be shown the Commission's Order of Investigation. Copies of Orders of Investigation shall not be furnished, for their retention, to such persons requesting the same except with the express approval of the director of the office responsible for the investigation. Such approval shall not be given unless the director of the office responsible for the investigation, in the director's discretion is satisfied that there exist reasons consistent with the protection of privacy of persons involved in the investigation and with the unimpeded conduct of the investigation.

(b) Any person compelled to appear, or who appears in person at a formal investigation by request or permission of the Investigating Officer may be accompanied, represented and advised by counsel, as provided by § 1.4 of the rules of practice and these rules, except that all witnesses shall be sequestered and, unless permitted in the discretion of the Investigating Officer, no witness or the counsel accompanying any such witness shall be permitted to be present during the examination of any other witness called in such proceeding. When counsel does represent more than one person in an investigation, for example, where the counsel is counsel to the witness and his employer, said counsel shall inform the Investigating Officer and each client of said counsel's possible conflict of interest in representing that client and, if said counsel appears with a witness giving testimony on the record in an investigation, counsel shall state on the record all persons said counsel represents in the investigation.

(c) Any witness may be accompanied, represented, and advised by counsel as follows:

(1) Counsel for a witness may advise the witness, in confidence, upon his initiative or the witness' with respect to any question, and if the witness refuses to answer a question, then the witness or counsel may briefly state on the record the legal grounds for such refusal.

(2) Where it is claimed that the witness has a privilege to refuse to answer a question on the grounds of self-incrimination, the witness must assert the privilege personally.

(3) Following completion of the examination of a witness, such witness may make a statement on the record and his counsel may on the record question the witness to enable the witness to clarify any of the witness' answers or to offer other evidence.

(4) The Investigating Officer shall take all necessary action to regulate

the course of the proceeding to avoid delay and prevent or restrain obstructionist or contumacious conduct or contemptuous language. Such officer may report to the Commission any instances where an attorney or representative has refused to comply with his directions, or has engaged in obstructionist or contumacious conduct or has used contemptuous language in the course of the proceeding. The Commission may thereupon take such further action as the circumstances may warrant, including suspension or disbarment of counsel from further appearance or practice before it, in accordance with § 1.4 of the Commission's rules of practice, and § 1100.11 of the rules of practice of the Interstate Commerce Commission, or exclusion from further participation in the particular investigation.

(d) Unless otherwise ordered by the Commission, in any public formal investigation, if the record shall contain implications of wrongdoing by any person, such person shall have the right to appear on the record; and in addition to the rights afforded other witnesses hereby, he shall have a reasonable opportunity of cross-examination and production of rebuttal testimony or documentary evidence. "Reasonable" shall mean permitting persons as full an opportunity to assert their position as may be granted consistent with administrative efficiency and with avoidance of undue delay. The determinations of reasonableness in each instance shall be made in the discretion of the investigating officer.

§ 1b.17 Appearance and practice before the Commission.

The provisions of § 1.4 of the Commission's rules of practice are specifically applicable to all investigations.

§ 1b.18 Right to submit statements.

Any person may, at any time during the course of an investigation, submit documents, statements of facts or memoranda of law for the purpose of explaining said person's position or furnishing evidence which said person considers relevant regarding the matters under investigation.

§ 1b.19 Submissions.

When the Investigating Officer determines it is appropriate in the interest of the proper administration of the law, he may inform any person that a recommendation may be made to the Commission that said person be a defendant in a civil action to be brought by the Commission. In such case, said person may submit a statement of fact, argument, and/or memorandum of law, with such supporting documentation as said person chooses showing why said person should not be a defendant in any civil action brought by the Commission. The investigating officer shall inform said potential defendant of the date by which such statement may be submitted to said officer, and if such statement is submitted by such date, it shall be presented to the Commission together with any recommendation for enforcement action by the office responsible for the investigation.

§ 1b.20 Request for confidential treatment.

Any person compelled to produce documents in an investigation may claim that some or all of the information contained in a particular document(s) is exempt from the mandatory public disclosure requirements of the Freedom of Information Act (5 U.S.C. 552), is information referred to in 18 U.S.C. 1905, or is otherwise exempt by law from public disclosure. In such case, the person making such claim shall, at the time said person produces the document to the officer conducting the investigation shall also produce a second copy of the document from which has been deleted the information for which the person wishes to claim confidential treatment. The person shall indicate on the original document that a request for confidential treatment is being made for some or all of the information in the document and shall file a statement specifying the specific statutory justification for non-disclosure of the information for which confidential treatment is claimed. General claims of confidentiality are not sufficient. Sufficient information must be furnished for the officer conducting the investigation, or other appropriate official, to make an informed decision on the request for confidential treatment. If the person states that the information comes within the exception in 5 U.S.C. 552(b)(4) for trade secrets and commercial or financial information, the person shall include a statement specifying why the information is privileged or confidential. If the person filing a document does not submit a second copy of the document with the confidential information deleted, the Officer conducting the investigation may assume that there is no objection to public disclosure of the document in its entirety. The Commission retains the right to make the determination with regard to any claim of confidentiality. Notice of the decision by the investigating Officer or other appropriate official to deny a claim, in whole or in part, and an opportunity to respond shall be given to a person claiming confidentiality no less than 5 days before its public disclosure.

[FR Doc. 78-17376 Filed 6-22-78; 8:45 am]

[¶ 30,013]

43 F. R. 27178 (June 23, 1978)

PART 260—STATEMENTS AND REPORTS (SCHEDULES)

Order Discontinuing Requirements to File FPC Form 69 for Respondents Who Submit Data on EIA Form 50

JUNE 14, 1978.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Order.

SUMMARY: This order discontinues the requirement for interstate natural gas pipeline companies to file FPC Form 69. EIA has developed Form EIA-50 to collect the data previously reported on Form 69.

EFFECTIVE DATE: The order will become effective with the promulgation of Form EIA-50 by EIA.

FOR FURTHER INFORMATION:

FPC Form 69, contact: Randolph Mathura, Room 7312, 825 North Capitol Street NE., Washington, D.C. 20426, 202-275-4489.

EIA-50, contact: June A. Wolfrey, Energy Information Administration, Washington, D.C. 20461, 202-254-8461.

On October 1, 1977, pursuant to the provisions of the Department of Energy Organization Act, Pub. L. 95-91, approved August 4, 1977, 91 Stat. 565, 42 U.S.C. 7101 *et seq.* (DOE Act), and Executive Order No. 12009, dated September 13, 1977 (42 FR 46267, September 15, 1977), the Federal Power Commission (FPC) ceased to exist and its functions and regulatory responsibilities were transferred to the Secretary of Energy and the Federal Energy Regulatory Commission (FERC), which, as an independent regulatory commission within the Department of Energy, was activated on October 1, 1977.[1] The "savings provisions" of section 705(a) of the DOE Act provide that all rules and regulations issued by any Federal agency in the performance of functions which are transferred under the DOE Act to the Department of Energy or the FERC after the date of enactment of the DOE Act, and which are in effect at the time the DOE Act takes effect, shall continue in effect until modified, terminated, superseded, set aside or revoked by the Secretary of Energy or the FERC, or by operation of law.

The Secretary of Energy by Delegation Order No. 0204-1, effective October 1, 1977 (42 FR 55637, October 18, 1977), delegated and assigned to the FERC the authority to carry out functions under section 10 of the Natural Gas Act relating to annual and periodic or special reports "as FERC determines appropriate to perform its vested or delegated functions". The Delegation Order directs the FERC to consult with the Administrator of the Energy Information Administration (EIA) of the Department of Energy with respect to the exercise of functions under section 10 of the Natural Gas Act "as EIA considers appropriate". Section 0.4(h) of Part O of Chapter I, Title 18 of the Code of Federal Regulations, which was promulgated by the FERC's Order No. 1, Docket No. RM78-1, issued October 6, 1977 (42 FR 55450, October 17, 1977), provides that all persons or jurisdictional entitics required to file periodic or other reports with any agency or commission whose functions were transferred under the DOE Act to the FERC shall file such reports relating to the transferred functions with the FERC and provides further that the FERC affirms, adopts and continues in effect all previously approved forms for making periodic or other reports.

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[1] The term "Commission" when used in the context of an action taken prior to October 1, 1977, refers to the FPC; when used otherwise, the reference is to the FERC.

On June 25, 1973, the Commission issued Order No. 531 setting forth a new Form No. 69 which was the result of a coordinated effort undertaken with the Federal Energy Administration (FEA), other governmental agencies and the National Association of Regulatory Utility Commissioners. The Commission issued Order No. 531-A on July 9, 1975, and Order No. 531-C on May 19, 1976, each revising and clarifying Form No. 69 in order to make it fully conform with the FEA's concurrent Form No. G-101-A-2.

The EIA has been utilizing Form Nos. G-101-A-2 and 69, as amended, to accumulate the information needed to determine the type and quantities of alternate fuels that will be required in order to offset the loss of natural gas due to the curtailment of deliveries by interstate pipelines and the general dwindling supply of that resource.

The FERC uses the information to perform its duties under the Natural Gas Act in determining that pipeline company curtailment plans are in the public interest.

The EIA now proposes to issue a new Form, EIA-50, which will provide the data that have been called for on Form G-101-A-2 and FPC Form No. 69 with these minor changes:

(a) Some of the instructions have been rearranged.

(b) Two new definitions have been added:

Alternate Fuels: Any fuel purchased by an end-use customer to offset natural gas curtailments by his supplier. Included as alternate fuels are gaseous fuels purchased under FERC Order 533 and self-help procedures such as exist in the State of Ohio.

Supplemental Gaseous Fuels: Gaseous fuels, either purchased or produced by the supplier, distributed through mains to end-use customers in order to supplement natural gas.

(These additions represent the formalization of definitions that have been in general use by respondents.)

(c) The identification of the person to contact has been moved to the first page of the form.

(d) Verification procedures for Part II C have been added.

These minor revisions do not change the reporting burden.

The Commission finds: (1) Because Form EIA-50 includes only minor revisions in the form of Form 69, rather than new substantive requirements, this matter is procedural, and accordingly notice and public procedure under 5 U.S.C. 553 are not required.

(2) Because the consolidation of the two forms will minimize reporting requirements, good cause exists that Form EIA-50 should replace FPC Report Form No. 69 as soon as it is officially issued by EIA, and that interstate natural gas pipeline companies should file Form EIA-50 directly with the EIA.

(3) On Form EIA-50 EIA will collect data formerly supplied on FPC Form 69 and will be able to provide the same statistical summaries as well as the same detailed statistics.

(4) Data on curtailments and alternate fuels as needed by the FERC will be available from the EIA.

(5) Statistics on Form EIA-50 will be available to the public to the same extent as they have been on FPC Form No. 69.

(6) Form EIA-50 does not increase the reporting burden of any respondent who has been filing FPC Form No. 69.

(7) This action does not set a precedent for future handling of FPC forms.

(8) This change in reporting requirements is appropriate for the Administration of the Natural Gas Act.

The Commission, acting pursuant to the provisions of the Natural Gas Act, as amended, particularly section 16 and section 10 thereof (52 Stat. 826, 830; 15 U.S.C. 717; and 717o), *orders:*

(A) FPC Form No. 69 as promulgated by section 260.15 and section 3.170 of Title 18 of the Code of Federal Regulations is accordingly no longer required from interstate natural gas pipeline companies that file Form EIA-50 with the EIA.

(B) This change in reporting requirement shall be effective for any respondent with his filing of Form EIA-50 as noted in Paragraph (A) above.

(C) The Secretary shall cause prompt publication of this order to be made in the FEDERAL REGISTER.

By the Commission.

KENNETH F. PLUMB,
Secretary.

[FR Doc. 78-17426 Filed 6-22-78; 8:45 am]

[¶ 30,014]

43 F. R. 34454 (August 4, 1978)

SUBCHAPTER G—APPROVED FORMS, NATURAL GAS ACT

[Order No. 526-D; Docket No. RM74-16]

PART 260—STATEMENTS AND REPORTS (SCHEDULES)

Order to Extend 1977 Filing Date of Required Schedules

JULY 31, 1978.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Order to extend 1977 filing date of required schedules.

SUMMARY: Order No. 526-D of the Federal Regulatory Commission amends order No. 526-C (Docket No. RM74-16) with regard to the filing date of form 40 schedules for report year 1977, deferring that date from September 1, 1978 to December 1, 1978. In the near future, the Energy Information Administration's proposed form EIA-23 may go into effect. The filing extension is to enable the Commission to take appropriate action to prevent duplicate reporting should form EIA-23 be adopted.

DATES: Form No. 40 submittals for calendar year ending December 31, 1977 must be filed by December 1, 1978.

FOR FURTHER INFORMATION CONTACT: John Conway, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, 202-275-4788.

On February 17, 1978, this Commission issued its order No. 526-C (Docket No. RM74-16) which, among other things, extended the filing date for form No. 40 schedules for report year 1977 from April 1, 1978, to September 1, 1978. this order amends order No. 526-C to further extend the filing date for 1977 from September 1, 1978, to December 1, 1978.[1]

Currently, the Energy Information Administration of the Department of Energy is taking steps to promulgate a new form, proposed form EIA-23. Upon approval by the Office of Management and Budget, this new form will become operative. Should this approval be forthcoming in the near future, as is now expected, an unnecessary burden may be placed upon those who are required to report under the provisions of the Commission's order No. 526-C; they may be required to report what is essentially the same information on two different forms. This potential for the duplication of effort on the part of all concerned should be avoided. To this end the Commission is today ordering that the filing date for form No. 40's required schedules for report year 1977 be extended from September 1, 1978 to December 1, 1978. This extension will enable the Commission, if circumstances warrant, to take appropriate action to prevent duplicate reporting should proposed form EIA-23 go into effect.

The Commission finds: (1) On its own motion, and for the reasons stated above, that the filing date for

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[1] This proceeding was commenced before the FPC. By the joint regulation of October 1, 1977 (10 CFR 1000.1), it was transferred to the FERC.

1977 reporting of form No. 40 should be modified as set forth herein.

(2) The modification so made, to extend the filing date for report year 1977, is to insure ease of compliance with the Commission's order No. 526-C while at the same time minimizing the potential for duplicative reporting.

(3) That for the reasons given above, and in that this order relieves a restriction previously imposed to the extent of extending a filing date, good cause exists to dispense with notice and public procedures; and this order may therefore be made effective immediately.

(4) An amendment to § 260.13(d), of part 260 of the Commission's regulations is necessary and appropriate for the administration of the Natural Gas Act.

The Commission orders: (A) Section 260.13(d), part 260, subchapter G of chapter I, title 18 of the Code of Federal Regulations is amended to read as follows:

260.13 Form No. 40, natural gas companies annual report of proved domestic reserves.

* * * * *

(d) Paragraphs (b) and (c) apply to calendar year 1976 and subsequent years, except that Schedule C is not required for 1976. The FPC form No. 40 shall be filed by March 1, 1978 for the calendar year ending December 31, 1976, by December 1, 1978 for the calendar year ending December 31, 1977, and thereafter shall be filed by April 1 of the year following the year to which the form applies.

(B) The effective date of this order shall be the date of issuance.

(C) The Secretary shall cause prompt publication of this order to be made in the FEDERAL REGISTER.

By the Commission.

KENNETH F. PLUMB,
Secretary.

[FR Doc. 78-21701 Filed 8-3-78; 8:45 am]

[¶ 30,015]

43 F. R. 35907 (August 14, 1978)

PART 1—RULES OF PRACTICE AND PROCEDURE

Procedures for Review by the Federal Energy Regulatory Commission of Adjustment Request Denials by the Secretary of Energy

AGENCY: Federal Energy Regulatory Commission.

ACTION: Interim regulations.

SUMMARY: Section 504(b) of the Department of Energy Organization Act provides that if any person is aggrieved or adversely affected by a denial by the Secretary of a request for adjustment to certain regulations of the Department of Energy, the person may request a review of the denial by the Federal Energy Regulatory Commission (Commission). Accordingly, the Commission is amending its rules of practice and procedure by adding a new interim rule to provide procedures for Commission review of denials by the Secretary of Energy of requests for adjustments.

DATES: Effective date: August 8, 1978. Other Dates: Written comments—September 15, 1978; public hearing September 8, 1978; requests to participate in public hearing September 1, 1978.

FOR FURTHER INFORMATION CONTACT:

Alexander M. Peters, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, 202-275-4227.

Bonnie Cord, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, 202-275-4210.

A. BACKGROUND

Section 504(a) of the Department of Energy Organization Act (DOE Act), Pub. L. 95-91, requires that the Secretary of Energy (Secretary), or any officer designated by him, provide for the making of adjustments to certain rules, regulations or orders, as may be necessary to prevent special hardship, inequity, or unfair distribution of burdens. The rules, regulations, and orders to which this requirement applies are those issued under the Federal Energy Administration Act, the Emergency Petroleum Allocation Act of 1973, the Energy Supply and Environmental Coordination Act of 1974, or the Energy Policy and Conservation Act.

Section 504(b) of the DOE Act provides in paragraph (1) that if any person is aggrieved or adversely affected by a denial by the Secretary of a request for adjustment under subsection (a), the person may request a review of the denial by the Federal Energy Regulatory Commission (Commission). Paragraph (2) of section 504(b) requires that the Commission by rule establish appropriate procedures, including a hearing when requested, for review of a denial.

The statement of managers accompanying the conference report on the DOE Act states that responsibility to review adjustment request denials was placed in the Commission rather than elsewhere in the Department of Energy (Department) to assure that the Department's review of any initial action taken with respect to adjustment requests would be by officials who were in no way involved in the initial action. The conferees also emphasized that the procedures specified in section 504

> * * * are intended to clearly reaffirm the intent of Congress that those involved in * * * proceedings involving requests for adjustments be extended procedural due process. Congress always intended that the notions of fair play and due process be followed in the administrative process. (S. Rep. No. 95-367, 95th Cong., 1st sess. 85-86 (1977).)

The Commission is issuing the regulations set forth below to provide the procedures required for its review of denials of adjustment requests. They are being issued for public comment and will be the subject of a public hearing, but will also be effective in the interim with respect to any reviews the Commission must conduct before the rules can be issued in final form.

The rules of the Department providing for adjustments are set forth in 10 CFR Part 205, Subpart D (Exceptions). The Commission requests that parties offering comments on its interim and proposed rules take the Department's procedures into account.

B. SUMMARY

These interim and proposed procedures are provided for in a new § 1.40 (18 CFR 1.40). They are intended to implement the Commission's authority under section 504 of the DOE Act, and apply to the review of any denial of an adjustment request. In this regard, the Commission intends to consider review requests with regard to either full or partial denials. In the Commission's view, however, its statutory authority does not extend to review of grants of adjustments. The Commission intends to consider every request to review a denial or partial denial, reserving, however, the discretion to determine whether a person is actually aggrieved or adversely affected, and if not whether to dismiss the person's request without further proceedings.

Paragraph (d) of § 1.40 provides that a petitioner (defined in paragraph (b) as the aggrieved or adversely affected person who requests Commission review) may commence proceedings under this section by filing, within 30 days of issuance of the contested order, a petition for review. The petition must contain a copy of the contested order, a statement of objections to the factual or legal basis of the order, and references to all authorities relied upon. Paragraph (d) also provides for requests for interim relief and designation by the Commission of a presiding officer.

Paragraph (e) provides for replies by the Secretary, who, within 15 days of service of the petition for review, must certify to the Commission a copy of the record compiled in prior proceedings and a reply to the petition for review. Replies and other submittals may be filed, as determined by the presiding officer, by other persons who were parties in prior proceedings and by any person permitted to intervene upon a showing that he or she was wrongfully denied the prior opportunity to participate or is aggrieved or adversely affected by the contested order. Paragraph (e) also states that the presiding officer may require other filings by the participants as necessary in the conduct of the proceedings.

Paragraph (f) provides for a request by a participant for a hearing. The request will be deemed granted, consistent with section 504(b)(2).

The conduct of the proceeding, and of the hearing, if one is requested, is generally left to the discretion of the presiding officer, who must determine the issues to be resolved and the nature of the hearing to be held. The presiding officer may also permit the raising of new facts or issues under the circumstances set forth in paragraph (g)(ii).

Paragraph (i) requires that a participant seeking relief from the Secretary's denial of a request for adjustment, bears the burden of demonstrating that the adjustment should be granted. Such a burden will be satisfied if the participant can show, by a preponderance of the evidence, that the relief sought is warranted.

After receiving pleadings and any other information required, and after the hearing, the presiding officer is directed to prepare a proposed order, and to certify it along with the record, to the Commission. The participants may within 15 days of service upon them of the proposed order submit comments on the proposed order to the Commission. Such comments should address any objections the participants have to the proposed order. The proceeding is ended by issuance by the Commission of a final order affirming, modifying, or vacating the contested order or directing other appropriate relief.

The provisions of § 1.4(d) of the Commission's rules of practice and procedure apply with respect to ex parte communications in a § 1.40 proceeding from the time of filing of a petition for review as if the proceeding were a contested on-the-record proceeding pending before the Commission.

The treatment of confidential information is set out in paragraph (c), which provides that information filed by a person under this section may be withheld from public discloure if the person: (1) Claims that the material is exempt from the mandatory disclosure requirements of the Freedom of Information Act (5 U.S.C. 552), is information referred to in 18 U.S.C. 1905, or is otherwise exempt from public disclosure; (2) requests the presiding officer not to disclose the information and serves that request on the other participants in the proceeding; (3) submits a copy of the document with the information deleted; (4) indicates in the original document that nondisclosure is requested; and (5) includes a statement justifying the request for nondisclosure. Other participants may oppose the request for nondisclosure by filing, within 10 days of receiving a copy of the request, and serving on the other participants a statement specifying the reasons that the information is not exempt from public disclosure. The presiding officer must make an independent determination as to any request for nondisclosure, and serve that determination upon all participants in the proceeding. If the request is denied, the requesting person will be given an opportunity to respond at least 5 days before public disclosure. If the request for nondisclosure is granted, the presiding officer issues an order stating that the information may be disclosed, upon request, only to other participants in the proceedings, that the other participants may not use or disclose the information except in the context of the proceedings conducted under this section, and that, upon the conclusion of the proceedings, all participants shall return the information to the presiding officer.

C. Effective Date

These regulations are being issued effective immediately on an interim basis because the Commission finds that the need to have regulations in place implementing section 504 of the DOE Act to apply to any requests for Commission review prior to the issuance of final rules constitutes good cause to find prior notice and public procedure to be impracticable, and to waive publication not less than 30 days prior to the effective date. The Commission requests data, views, or arguments with respect to these regulations and will also hold a public hearing. After evaluating the information received, the Commission will make any appropriate revisions to these regulations.

D. WRITTEN COMMENT PROCEDURES

Interested persons are invited to submit written comments, data, views, or arguments with respect to this proposal. An original and 14 copies should be filed with the Secretary of the Commission. All comments received prior to September 15, 1978, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, 825 North Capitol Street NE., Washington, D.C., during regular business hours. Comments should be submitted to the Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, and should reference docket No. RM78-17.

E. PUBLIC HEARING PROCEDURES

A public hearing concerning this proposal will be held in Washington, D.C., on September 8, 1978, beginning at 9:30 a.m. and will continue if necessary on the following day. Any person interested in this proceeding or representing a group or class of persons interested in this proceeding may make a presentation at the hearing provided a written request to participate is received by the Secretary of the Commission prior to 4:30 p.m., on September 1, 1978.

Requests to participate in the hearing should include a reference to Docket No. RM-78-17, as well as a concise summary of the proposed oral presentation and a number where the person making the request may be reached by telephone. Prior to the hearing each person filing a request to participate will be contacted by the presiding officer or his designee for scheduling purposes. At least five copies of the statement shall be submitted to the Secretary of the Commission prior to 4 p.m., on September 1, 1978. The presiding officer is authorized to limit oral presentation at the public hearing both as to length and as to substance. Persons participating in the public hearing should, if possible, bring 100 copies of their testimony to the hearing.

The hearing will not be a judicial or evidentiary-type hearing. There will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested person may submit questions to the presiding officer to be asked of persons making statements. The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. If time permits, at the conclusion of the initial oral statements, persons who have made oral statements will be given the opportunity to make a rebuttal statement. Any further procedural rules will be announced by the presiding officer at the hearing. A transcript of the hearing will be made available at the Commission's Office of Public Information.

(Department of Energy Organization Act, Pub. L. 95-91; E.O. 12009, 42 FR 46267.)

In consideration of the foregoing, part I, subchapter A, chapter I of title 18, Code of Federal Regulations, is amended as set forth below, effective immediately.

By direction of the Commission.

KENNETH F. PLUMB,
Secretary.

1. Part 1, subchapter A, chapter I of title 18, Code of Federal Regulations, is amended in the table of contents by adding in the appropriate numerical order a new section number and heading to read as follows:

* * * * *

§ 1.40 Commission review of adjustment request denials.

* * * * *

2. Part 1, subchapter A, chapter I of title 18, Code of Federal Regulations, is amended by adding a new § 1.40, to read as follows:

§ 1.40 Commission review of adjustment request denials.

(a) *Scope.* (1) This section applies to proceedings of the Commission held in accordance with section 504(b) of the Department of Energy Organization Act, Pub. L. 95-91, 42 U.S.C. 719(b), to review orders issued by the Secretary of Energy pursuant to section 504(a) of the Department of Energy Organization Act denying, in whole or in part, requests for adjustments.

(2) Except as otherwise specifically provided in this section, the following provisions of this part apply to proceedings under this section:

(i) § 1.1—The Commission;

(ii) § 1.2—The Secretary;

(iii) § 1.3—Notice of public sessions and proceedings;

(iv) § 1.4—Appearances and practice before the Commission;

(v) § 1.8—Intervention (except for paragraph (b));

(vi) § 1.12—Amendments and withdrawal of pleadings;

(vii) § 1.12—Motions;

(viii) § 1.13—Time, extensions of time, issuance of orders;

(ix) § 1.14—Filings, docket and hearing calendar;

(x) § 1.15—Formal requirements as to pleadings, documents, and other papers filed in proceedings;

(xi) § 1.16—Subscription and verification;

(xii) § 1.17—Service;

(xiii) § 1.21—Copies of transcripts;

(xiv) § 1.22—Witnesses;

(xv) § 1.23—Subpenas.

(xvi) § 1.2—Depositions;

(xvii) § 1.25—Stipulations;

(xviii) § 1.26—Evidence;

(xix) § 1.27—Presiding officer;

(xx) § 1.36—Public information and requests; and

(xxi) § 1.51—Certificate of service.

(b) *Definitions.* For purposes of this section—

(1) "Commission" means the Federal Energy Regulatory Commission or its officer or employee designated as presiding officer in a proceeding under this section.

(2) "Petitioner" means a person who is aggrieved or adversely affected by a contested order, as defined in this paragraph, and who requests a review, pursuant to this section, by the Commission of the denial by the Secretary.

(3) "Secretary" means the Secretary of Energy or his delegate.

(4) "Contested order" means the decision or order issued by the Secretary denying, in whole or in part, a request for adjustment.

(5) "Participant" means, as appropriate, the petitioner, the Secretary, or any intervenor.

(c) *Request for nondisclosure of information.* (1) For purposes of this paragraph, nondisclosure means nondisclosure except to the participants in the proceedings and under the conditions as provided in paragraph (c)(5) of this section.

(2) If any person filing under this section claims that some or all of the information contained in a document is exempt from the mandatory public disclosure requirements of the Freedom of Information Act (5 U.S.C. 552), is information referred to in 18 U.S.C. 1905, or is otherwise exempt by law from public disclosure, the person:

(i) Shall request the presiding officer not to disclose such information, except to the participants in the proceedings and under the conditions as provided in paragraph (c)(5) of this section, which request the person shall serve upon all participants in the proceedings;

(ii) Shall file, together with the document, a second copy of the document from which has been deleted the information for which the person requests nondisclosure and shall indicate in the original document that the original document is confidential or contains confidential information;

(iii) If the information is claimed to come within the exception in 5 U.S.C. 552(b)(4) for trade secrets and commercial or financial information, the person shall include a statement specifying why the information is privileged or confidential;

(iv) If the information for which nondisclosure is requested is not within the exception in 5 U.S.C. 552(b)(4), the person shall include a statement specifying the justification for nondisclosure.

(3) If the person filing a document does not submit a second copy of the document from which the appropriate information has been deleted, the presiding officer may assume that there is

no objection to public disclosure of the document in its entirety.

(4) A participant in the proceedings who opposes a request for nondisclosure under paragraph (c)(2) of this section shall, within 10 days of the receipt of a copy of the request for nondisclosure, file with the presiding officer, and serve on the other participants, a statement specifying the reasons that the material is not exempt from disclosure.

(5) The presiding officer shall make an independent determination as to any request filed under this paragraph and shall serve that determination upon all participants in the proceedings. If a request for nondisclosure is denied, in whole or in part, the requesting person will be given notice thereof and shall be afforded an opportunity to respond, no less than 5 days prior to public disclosure. If the request for nondisclosure is granted, in whole or in part, the presiding officer will issue an order stating that the information will not be disclosed except, upon request, to the participants in the proceedings, that the participants may not use or disclose the information, except in the context of the proceedings conducted pursuant to this section, and that, upon conclusion of the proceedings, all participants return the information to the presiding officer.

(d) *Commencement of proceedings.* (1) A petitioner shall commence proceedings, pursuant to this section, by filing with the Commission and serving upon the Secretary and any other participants in prior proceedings on the contested order a petition for review, which shall contain:

(i) A copy of the decision or order denying, in whole or in part, request for adjustment (the contested order); and

(ii) A complete statement of the petitioner's objections factual or legal to the contested order, including references to all authorities upon which the petitioner relies including but not limited to regulations, rulings, interpretations, and decision on exceptions and appeals issued by the Department or its predecessor agencies, and precedents established by the Commission.

(2) A petition for review must be filed within 30 days of issuance by the Secretary of the order to be contested pursuant to this section.

(3) Upon receiving a petition for review, the Commission or its designee shall designate a presiding officer for the proceedings.

(e) *Replies.* (1) *By the Secretary.* Within 15 days of service of the petition for review, the Secretary (i) shall file with the Commission a certified copy of the complete record developed in prior proceedings on the contested order, which shall be available at the Commission for inspection by the participants; and

(ii) Shall file with the Commission and serve on the petitioners and the other participants in prior proceedings on the contested order, a reply to the petition for review stating fully his position supported by arguments to the petition for review.

(2) *By other participants.* Any person who participated in prior proceedings on the contested order may be a participant in the proceedings pursuant to this section and may make filings and submittals as determined by the presiding officer.

(3) *By intervenors.* Any person who was denied the opportunity to participate in prior proceedings on the contested order or who is aggrieved or adversely affected by the contested order may petition to intervene in accordance wih § 1.8. In order that the petition be granted, the petitioner must show, as appropriate, that denial of participation in prior proceedings was wrongful or why he or she is aggrieved or adversely affected by the contested order. If the presiding officer grants the petition, the person submitting the petition to intervene may make filings and submittals as determined by the presiding officer.

(4) Any participant may request interim relief in a proceeding pursuant to this section.

(5) The presiding officer may require such other filings by the participants as he or she deems necessary in the conduct of the proceedings.

(f) *Request for hearing.* Any participant may file with the Commission and serve on the other participants a request for hearing, which shall be deemed granted.

(g) *Presiding officer.* (1) The presiding officer shall determine the issues to be resolved in the proceeding and shall give notice thereof to the participants. The presiding officer may require additional information from the participants and convene a prehearing conference for the purpose of determining the issues to be considered at a hearing, if one is to be held. The presiding officer may also specify the time available for oral argument and determine the nature of the hearing to be held.

(2) The presiding officer may determine, upon request by a participant, whether to permit the participant to raise new facts or issues not raised in prior proceedings on the contested order. Such a request may be granted if the facts or issues are facts or issues that: (i)(A) were not known and could not, with the exercise of due care, have been known to the participant at the time they could have been raised in prior proceedings; or (B) are facts or issues that the participant was not permitted to raise in prior proceedings on the contested order due to adverse procedural ruling alleged to be erroneous; and (ii) are necessary for a full and true disclosure of the facts.

(h) *Hearings.* (1) As soon as practicable, after receiving any request for hearing and all the pleadings under paragraphs (d) and (e) of this section, the presiding officer shall give notice to all participants as to the time and place of the hearing.

(i) *Proof.* (1) Any participant seeking relief from the Secretary's denial of a request for an adjustment has the burden of demonstrating the participant's entitlement to the relief sought.

(2) Relief shall be granted under this subpart if a participant demonstrates, by a preponderance of the evidence, that such relief is warranted.

(j) *Proposed order.* (1) As soon as practicable, after receipt of all the pleadings or after the hearing, if one is held, the presiding officer shall issue, and serve upon all participants in the proceedings, a proposed order based upon findings of fact, affirming, modifying or vacating the contested order or directing other appropriate relief.

(2) The presiding officer shall certify and file with the Office of the Secretary of the Commission, for the Commission, a copy of the record in the proceeding, including the proposed order.

(3) Participants may within 15 days of service of the proposed order of the presiding officer file, with the Secretary of the Commission, for the Commission, written comments on the proposed order.

(k) *Final order.* The Commission shall issue a final order affirming, modifying or vacating the contested order or directing other appropriate relief.

(l) *Ex parte communications.* The provisions of § 1.4(d) of this subpart shall apply to proceedings pursuant to this section, commencing at the time a petitioner files a petition for review under paragraph (d)(1) of this section, as if such proceedings were contested on-the-record proceedings pending before the Commission.

[FR Doc. 78-22664 Filed 8-11-78; 8:45 am]

[¶ 30,016]

43 F. R. 36433 (August 17, 1978)

[Docket No. RM78-19]

DELEGATION TO VARIOUS OFFICE DIRECTORS OF CERTAIN COMMISSION AUTHORITY

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final regulations.

SUMMARY: The Federal Energy Regulatory Commission is amending its regulations in order to delegate certain routine ministerial Commission functions to various office directors. The amended regulations provide an opportunity for affected parties to challenge decisions made by staff pursuant to the delegated functions by petitioning the Commission for a prompt review.

best copy available

DATES: Effective date: August 14, 1978. Comment date: Written comments due on or before September 25, 1978.

ADDRESS: Secretary, Federal Energy Regulatory Commission, 825 North Capitol St. NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

Paul Equale, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, 202-275-3757.

Jane Phillips, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, 202-275-4788.

A. BACKGROUND

On October 1, 1977, pursuant to the provisions of the Department of Energy Organization Act (DOE Act) (Pub. L. 95-91, 91 Stat. 565 [August 15, 1977]) and Executive Order No. 12009 (42 F.R. 46267 [September 15, 1977]), the Federal Energy Regulatory Commission (the Commission) was established as an independent regulatory Commission within the Department of Energy. The functions and regulatory responsibilities of the Federal Power Commission were transferred to the Secretary of Energy and the Commission.

The powers transferred to the Commission include section 309 of the Federal Power Act (16 U.S.C. 825h) and section 16 of the Natural Gas Act (15 U.S.C. 717o), which provide that the Federal Power Commission "shall have power to perform any and all acts and to prescribe, issue, make, amend, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act."

The Commission has determined that an inordinate amount of time is being spent on matters that can be fairly characterized as routine. While recognizing the importance of all items of business that come to the Commission for determination, the decision has been made that by delegating certain routine ministerial Commission functions to the various office directors, the Commission will be able to focus on more complicated and controversial tasks.

In general, the matters being delegated require limited discretionary decisionmaking on the part of the named office director. In the relatively few instances that such authority is delegated, parties affected by a delegated function may petition the Commission for a prompt review of the challenged staff decision [18 CFR § 1.7(d)].

The large majority of delegations require amendments to 18 CFR § 3.5. Several new paragraphs have been added to § 3.5 to include delegations to staff that were not previously made. There are minor conforming changes in other sections of Chapter 18.

B. SUMMARY

Section 1.8 is amended in order to give the presiding administrative law judge in a particular case, as well as the Commission, and the Secretary, the authority to issue orders granting or denying petitions to intervene in a pending proceeding. The amendment is being made for the sake of administrative efficiency.

Section 1.27 has been amended to conform with the new provisions of § 1.8.

Section 3.5 as currently constituted is deleted in its entirety [1] and a new § 3.5 is substituted.

Several delegations to the Secretary of the Commission (Secretary) formerly contained in § 3.5(a) have been deleted. The functions involved in the deleted delegation have either been newly delegated to office directors or have been deleted altogether because they are no longer necessary. Generally, the newly delegated functions are being transferred from the Secretary to either the Chief Accountant, the Director of the Office of Pipeline and Producer Regulation or the Director of the Office of Electric Power Regulation in order to allow those office heads to accept or reject certain rate filings and amendments to rate filings. The purpose of delegating these functions to the office heads rather than to the Secretary is to reduce the enormous adminstrative burden on the Secretary.

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[1] Except for paragraph (e), which was promulgated by the Commission on Feb. 10, 1978, pursuant to Commission Order No. 3. Paragraph (e) is a delegation to the Oil Pipeline Board and is to remain in effect as issued.

The Chief Accountant has been given the authority to sign routine correspondence and to make certain determinations regarding the issuance of securities and stocks by public utilities.

Both the Director of the Office of Pipeline and Producer Regulation and the Director of the Office of Electric Power Regulation are being delegated the Commission's authority to pass upon routine applications and filings in their respective offices. This authority includes the issuance of deficiency letters.

C. EFFECTIVE DATE

The Commission makes these regulations effective without prior notice and public procedure because they are interpretive rules, statements of policy, and rules of agency procedure and practice. Accordingly, pursuant to 5 U.S.C. § 553(b), public procedure and comment are not required. For the same reasons, the Commission finds good cause to make the regulations effective immediately. The Commission nevertheless welcomes interested members of the public to submit comments or suggestions regarding these regulations. The Commission and its staff will evaluate any information received from interested persons and will consider appropriate revisions to these regulations as a result of comments received. An original and 14 copies should be filed by September 25, 1978, with the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426. All comments should refer, on the cover page, to Docket No. RM78-19.

(Federal Power Act, as amended, 16 U.S.C. 792 et seq., Natural Gas Act, as amended, 15 U.S.C. 717 et seq., Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267 (September 12, 1977).)

For the reasons stated herein, Parts 1 and 3 of Subchapter A, Part 35 of Subchapter B, and Part 157 of Subchapter E of Chapter I, Title 18, Code of Federal Regulations, are amended as set forth below, effective immediately.

By the Commission.

LOIS D. CASHELL,
Acting Secretary.

PART 1—RULES OF PRACTICE AND PROCEDURE

§ 1.7 [Amended]

1. Section 1.7 is amended by deleting paragraph (d) and substituting a new paragraph (d) to read as follows:

* * * * *

(d) *Appeals from actions of the staff.* Any staff action, other than a decision or ruling of a presiding administrative law judge, taken pursuant to authority delegated to the staff by the Commission that would be final, but for the provisions of this paragraph, may be appealed to the Commission by any interested party. The challenged staff action may be appealed by filing a petition within 15 days of the action. Answers to such petitions may be filed by any party within 10 days of service of the petition. Petitions and answers filed under this paragraph shall conform to the requirements of §§ 1.15 through 1.17. An appeal from any ruling of a presiding administrative law judge shall conform to the requirements of § 1.28 of this chapter. The Commission considers its action on appeals made pursuant to this paragraph to be final agency action for purposes of judicial review.

2. Section 1.8 is amended by revising subparagraph (2) of paragraph (a), paragraph (d), paragraph (e), and subparagraph (2) of paragraph (f).

§ 1.8 Intervention.

(a) *Initiation of intervention.*

* * * * *

(2) Upon petition to intervene, by order of the Commission, the Secretary where an administrative law judge has not been designated, or the designated presiding administrative law judge in the proceeding, including oral or written requests to intervene presented for the first time at a prehearing conference or at the hearing. Whenever the designated presiding administrative law judge takes such action orally at the hearing, he or she shall promptly issue a written order confirming such action. Absent a finding of good cause to the contrary, late intervention is limited to prospective participation in a proceeding.

* * * * *

(d) *Filing and service of petitions.* Petitions to intervene and notices of intervention may be filed at any time following the filing of a notice of rate or tariff change, or of an application, petition, complaint, or other document seeking Commission action, but in no event later than the date fixed for the filing of petitions to intervene in any order or notice with respect to the proceedings issued by the Commission or its Secretary, unless, for good cause shown, the Commission or the designated presiding administrative law judge in the proceeding authorizes a late filing. Service shall be made as provided in § 1.17. Where a person has been permitted to intervene notwithstanding his failure to file his petition within the time prescribed in this paragraph, the Commission or the designated presiding administrative law judge may, where the circumstances warrant, permit the waiver of the requirements of § 1.26(c)(5) with respect to copies of exhibits for such intervener.

(e) *Answers to petitions.* Any party to the proceeding or staff counsel may file an answer to a petition to intervene, and in default thereof, may be deemed to have waived any objection to the granting of such petition. If made, answers shall be filed within 15 days after the date of service of the petition, but not later than 5 days prior to the date set for the commencement of the hearing, if any, unless for cause the Commission or the designated presiding administrative law judge with or without motion shall prescribe a different time. They shall in all other respects conform to the requirements of §§ 1.15 to 1.17, inclusive.

(f) *Notice and action on petitions.*

* * * * *

(2) *Action on petitions.* As soon as possible after the expiration of the time for filing answers to such petitions or default thereof, as provided in paragraph (e) of this section, the Commission or the designated presiding administrative law judge will grant or deny such petition in whole or in part or may, if found to be appropriate, authorize limited participation.

* * * * *

§ 1.14 [Amended]

3. Section 1.14 is amended in the next to the last sentence of subparagraph (2) of paragraph (a) by adding the words "or the appropriate office director" after the word "Secretary" and before the word "with."

4. Section 1.27 is amended in paragraph (b) by redesignating subparagraph (10) as subparagraph (11), and by inserting a new subparagraph (10) to read as follows:

§ 1.27 Presiding officers.

* * * * *

(b) *Authority delegated.*

* * * * *

(10) To rule on all petitions to intervene which are pending either at the time the presiding administrative law judge is designated to hear a particular case, or which are filed after the presiding administrative law judge is designated. This delegation is subject to the conditions set forth in § 1.8 of this chapter.

* * * * *

PART 3—ORGANIZATION; OPERATION; INFORMATION AND REQUESTS

5. Section 3.5 is amended by revising paragraphs (a), (b), and (d), and by adding new paragraphs (c), (f), and (g), to read as follows:

§ 3.5 Delegations of authority.

The Commission authorizes:

(a) The Secretary, or in the Secretary's absence, the Secretary's designee to:

(1) Sign official general correspondence on behalf of the Commission, except as otherwise provided in this section.

(2) Except as provided in § 1.8 of this chapter, prescribe, for good cause, a different time than that required by the Commission's rules of Practice and Procedure for filing by public utilities, licensees, natural gas companies, and other persons answers to complaints, petitions, motions, and other documents. Absent a waiver, no answers shall be required to be filed within less than ten days after the date of service of the document.

(3) Schedule hearings and issue notices thereof.

(4) Accept for filing notices of intervention and petitions to intervene by commissions and agencies of the States and the Federal government.

(5) Pass upon petitions to intervene before a presiding administrative law judge is designated. However, in cases where a presiding administrative law judge has been designated, the provisions of paragraph (c) of this section are controlling.

(6) Consolidate proceedings for hearing, and sever proceedings which have been previously consolidated.

(7) Deny motions for extensions of time which are filed later than the time prescribed by Part 1 of this chapter, except that such motions may be granted if good cause is shown.

(8) Reject any documents filed later than the time prescribed by an order or rule of the Commission, except that such documents may be accepted if good cause is shown.

(9) Waive requirements of the Commission's rules which govern matters of form, when consistent with the public interest in a particular case.

(10) Pass upon, in contested proceedings, questions of extending time for electric public utilities, licensees, natural gas companies, and other persons to file required reports, data, and information and to do other acts required to be done at or within a specific time by any rule, regulation, license, permit, certificate, or order of the Commission.

(11) Accept service of process on behalf of the Commission.

(12) Accept for filing bonds or agreements and undertakings submitted in rate suspension proceedings.

(13) Take the following actions on certificate and rate schedule filings of independent producers, where the sales involved are not of an interstate character, or where proposed interstate sales were never made:

(i) Upon requests of the filing party, vacate the order previously issued granting a certificate of public convenience and necessity; and

(ii) Cancel the prior acceptance of, and permit withdrawal of, the related rate schedule upon request of the filing party or where the certificate application is concurrently being or has been previously withdrawn.

(14) Publish notice of land withdrawals under section 24 of the Federal Power Act.

(15) Issue notices of applications filed under the Federal Power Act and the Natural Gas Act, fixing the time for filing comments, protests or petitions to intervene and schedule hearings on such applications when appropriate or required by law.

(16) Accept for filing rate schedules and supplements thereto, if any, submitted in compliance with conditions in certificates of public convenience and necessity, both temporary and permanent, issued under section 7 of the Natural Gas Act, when they meet the requirements prescribed by such certificates. The Secretary shall advise the filing party of such acceptance, the designation of the rate schedule, and the effective date of the rate schedule.

(17) Accept for filing amendments to agreements and contracts or rate schedules submitted in compliance with Commission orders accepting offers of rate settlements if such fil-

ings are in satisfactory compliance with such orders.

(18) Grant authorizations, pursuant to the provisions of § 35.1(a) of this chapter for a designated representative to post and file rate schedules of public utilities which are parties to the same rate schedule.

(19) Redesignate proceedings, licenses, certificates, rate schedules, and other authorizations and filing to reflect changes in the names of persons and municipalities subject to or invoking Commission jurisdiction under the Federal Power Act or the Natural Gas Act, where no substantive changes in ownership, corporate structure or domicile, or jurisdictional operation are involved.

(20) Change the appropriate hydroelectric project license article upon application by the licensee to reflect the specified reasonable rate of return as provided in § 2.15 of this chapter.

(21) Issue temporary certificates to independent producers pursuant to section 7 of the Natural Gas Act upon the finding that an emergency exists and based upon allegations presented in requests for temporary authorization to initiate the sale or transportation of natural gas in interstate commerce pursuant to § 157.28 of this chapter.

(22) Accept on behalf of the Commission:

(i) Rate filings of jurisdictional natural gas companies which involve rollover contracts; and

(ii) Statements of eligibility filed by producers of natural gas as defined in § 154.91 and § 157.40 of this chapter. Statements of eligibility are filed under § 2.56a(p) of this chapter.

(b) The Chief Accountant or in the Chief Accountant's absence, the Chief Accountant's designee to:

(1) Issue interpretations of the Uniform Systems of Accounts for public utilities, licensees, and natural gas companies.

(2) Pass upon proposed accounting entries submitted by public utilities, licensees and natural gas companies which require Commission approval under the Uniform System of Accounts, and which are consistent with applicable statutory requirements and Commission rules, regulations or orders, including the Uniform Systems of Accounts, or reject such entries when inconsistent with the foregoing, except that where the proposed accounting entries involve unusually large transactions or unique or controversial features, including the propriety of recognition for ratemaking purposes, the Chief Accountant shall present the entries to the Commission for consideration.

(3) Pass upon, when appropriate, applications, petitions, and requests submitted under General Instruction No. 12 of the Uniform Systems of Accounts prescribed for natural gas companies for approval to group certain gathering systems, or certain compressor stations for the purpose of complying with that portion of General Instruction No. 12 that requires a segregation of the cost of operating and maintaining each plant.

(4) Pass upon applications to increase the size or to combine property units of public utilities, licensees and natural gas companies.

(5) Sign all correspondence on behalf of the Commission:

(i) Relating to Annual Report Nos. 1, 1F, 2, 2A, and P; and,

(ii) With State regulatory commissions and agencies relating to accounting and auditing matters.

(6) Pass upon, when requested to do so by a public utility or licensee:

(i) Requests to enter into negotiations for the placement of securities.

(ii) The issuance of common stock for purposes of employee stock option plans, stock investment plans, and similar arrangements.

(iii) The issuance of short-term notes, including but not limited to commercial paper.

(iv) Guarantees of debt or securities issued pursuant to pollution control bond issues.

(v) The issuance under competitive bidding procedures of common stock, preferred stock, and bonds, the value of which amounts of $25,000,000 or less.

(c) The chief administrative law judge, and the administrative law judge designated to preside at a particular hearing, to exercise the power granted to a Presiding Officer by the Commission's rules of practice and procedure, particularly § 1.27 of this chapter.

(d) The Solicitor or in the Solicitor's absence, the Solicitor's designee to;

(1) File with the appropriate court of the United States a certified list of the materials comprising the record of any proceeding which involves the Commission;

(2) Retain appropriate materials; and

(3) Deliver such materials to the court as required.

* * * * *

(f) The Director of the Office of Pipeline and Producer Regulation or in the Director's absence, the Director's designee to:

(1) Pass upon the following types of applications or amendments to applications, provided that no formal opposition to the applications or amendments is timely filed with the Commission:

(i) Applications for natural gas pipeline certificates authorizing the construction and operation of facilities that have a construction cost of less than $100,000;

(ii) Abbreviated applications and amendments thereto, pursuant to § 157.7(b), (c), (d), (e), and (g) of this chapter;

(iii) Applications by a pipeline for the abandonment of pipeline gas purchase facilities with a construction cost of less than $100,000. This authority shall be exercised only in cases where the producer servicing the jurisdictional pipeline has received Commission approval to abandon service to the pipeline and service by the jurisdictional pipeline will not be affected;

(iv) Applications for temporary certificates for the transportation of natural gas to industrials, pursuant to § 2.79 of this chapter.

(v) Amendments to certificates for the transportation of natural gas, provided that;

(A) The transportation can be accomplished within a previously authorized level of service; and,

(B) The amendments requested do not effect changes in the price.

(2) Accept for filing all initial rate schedules, rate schedule changes, notices of changes in rate submitted by natural gas companies; and advise the filing party of such acceptance; waive the requirement of statutory notice for good cause shown; designate the rate schedule and supplements thereto and the effective date thereof. This authorization shall not apply to pipeline rate increases, or to any filings authorized by this subparagraph if there are timely protests or interventions to such filings.

(3) Reject a rate filing, submitted by a natural gas company unless accompanied by a request for waiver in conformity with § 1.14(a)(2) of this chapter but only if it fails patently to comply with applicable statutory requirements, Commission rules, regulations or orders.

(4) Accept for filing, data and reports submitted by natural gas companies required by Commission orders, or presiding officers' initial decisions, upon which the Commission has taken no further action, when such filings are patently in compliance with such orders or decisions, and when appropriate, to notify the filing party of such acceptance.

(5) Pass upon, in uncontested proceedings applications by natural gas companies for extensions of time to file required reports, data, and information and to perform other acts required, at or within a specific time by any rule, regulation, license, permit, certificate, or order of the Commission.

(6) Issue reports for public information purposes. Any report issued without Commission approval shall:

(i) Be of a noncontroversial nature; and

(ii) Contain the statement, "This report does not necessarily reflect the views of the Commission", in bold face type on the cover.

(7) Pass upon requests by natural gas companies to withdraw applications pursuant to § 1.11(d)(1) of this chapter, in any proceeding in which a hearing has been held or convened.

(8) Issue and sign deficiency letters regarding natural gas rate filings, certificate applications and abandonment applications.

(g) The Director of the Office of Electric Power Regulation or in the

Director's absence, the Director's designee to:

(1) Take appropriate action on any application for a determination or vacation with respect to lands of the United States reserved from entry, location, or other disposal under section 24 of the Federal Power Act.

(2) Pass upon applications by licensees, other Federal agencies and the States, to modify license conditions for a period of 1 year or less.

(3) Take appropriate action on drawings, maps, plans, or specifications showing hydroelectric project works "as built" that are submitted by a licensee for approval in response to the requirements of a license article or a Commission order.

(4) Approve, with respect to particular parcels of land within the project area of a licensed waterpower project, the conveyance by the licensee to another entity of an interest therein for use for a nonproject purpose, subject to the right of the licensee, its successors and assigns to use the land for all project purposes contemplated by the license for the project.

(5) Pass upon applications for amendments to licenses issued under the Federal Power Act for the authorization of changes of 10 acres or less in the area within the project boundary for which any proposed new land use would entail no significant environmental impact and no significant effect on operation or maintenance of the project or on the use of remaining project lands and water for project purposes.

(6) Pass upon applications for transfers of licenses from a licensee to a successor or assign under section 8 of the Federal Power Act.

(7) Pass upon applications for the surrender of transmission line licenses pursuant to Part 6 of this chapter.

(8) Pass upon requests by applicants to withdraw, pursuant to § 1.11(d)(3) of this chapter, any declaration of intention, or application for license, or amendment, under Part I of the Federal Power Act.

(9) Pass upon requests by licensees for exemption from the requirement of filing FPC Form No. 80, Licensed Projects Recreation, under § 8.11 of this chapter.

(10) Take appropriate action on technical plans pertaining to recreation, fish, wildlife, cultural resources, or water quality that are submitted by a licensee for approval in response to the requirements of a license article or Commission order.

(11) Issue preliminary permits to enable permittees to maintain priority of application for a license where no opposition in any form to the issuance of the permit is received by the Commission.

(12) Accept for filing all initial rate schedules and rate schedule changes except for changes which would result in rate increases, that are submitted by public utilities and licensees; waive the requirement of statutory notice for good cause shown, and advise the filing party of such acceptance; and designate rate schedules and the effective dates thereof.

This authorization shall not apply where adverse interventions are received upon the expiration of the date set for such protests or interventions by the Commission's public notice of such filings.

(13) Pass upon, in uncontested proceedings, applications for the extension of time for public utilities and licensees to file required reports, data, and information and to do other acts required to be done within a specific time period by any rule, regulation, license, permit, certificate or order of the Commission.

(14) Issue deficiency letters regarding electric rate schedule filings, corporate applications for the sale of facilities with respect to interlocking directorates, and applications filed under Part I of the Federal Power Act.

(15) Reject a rate filing or an application filed under Part I of the Federal Power Act, unless accompanied by a request for waiver in conformity with § 1.14(a)(2) of this chapter, if it fails patently to comply with applicable statutory requirements or Commission rules, regulations and orders.

(16) Accept for filing data and reports submitted by public utilities and licensees that are required by Commission orders and presiding officers' initial decisions when such filings are patently in compliance with the orders or decisions; and, when appropriate,

notify the filing party of such acceptance.

(17) Take appropriate action on proposals for the development of water resources projects submitted by other agencies of the Federal government for Commission review or comment. The Director or his designee shall direct comments, when necessary, to the sponsoring agency on matters including, but not limited to, the need for, and appropriate size of, any hydroelectric power installation proposed by any other agency of the Federal government.

(18) Issue Appraisal and Planning Status Reports regarding water planning or development activities in specific river basins. The reports shall contain the statement, "This report does not necessarily reflect the views of the Commission," unless the report is specifically approved by the Commission.

(19) Prepare and issue comments on general water policy and planning issues, for the use of the Director of the Water Resources Council or the Assistant Secretaries of the Department of Energy.

(20) Pass upon applications filed by persons seeking to hold interlocking positions under section 305(b) of the Federal Power Act. This authority shall not be exercised in cases where a protest or adverse intervention is timely filed with the Commission.

(21) Pass upon applications for the sale of jurisdictional facilities under Section 203 of the Federal Power Act. This authority shall not be exercised in cases where an adverse intervention is timely filed with the Commission.

PART 35—FILING OF RATE SCHEDULES

§ 35.2 [Amended]

6. Section 35.2 is amended in the final sentence of paragraph (c) by deleting the word "Secretary," and inserting in lieu thereof "Director of the Office of Electric Power Regulation".

PART 157—APPLICATIONS FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND FOR ORDERS PERMITTING AND APPROVING ABANDONMENT UNDER SECTION 7 OF THE NATURAL GAS ACT

§ 157.8 [Amended]

7. Section 157.8 is amended by substituting the words "Director of the Office of Pipeline and Producer Regulation" for the word "Secretary" wherever it appears.

[FR Doc. 78-22975 Filed 8-16-78; 8:45 am]

[¶ 30,017]

43 F. R. 39982 (September 8, 1978)

SUBCHAPTER A—GENERAL RULES

[Docket No. RM78-20]

PART 1—RULES OF PRACTICE AND PROCEDURE

References to the Record in Briefs Filed With the Commission

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is amending its procedural regulations relating to briefs on exceptions. In addition to existing requirements, briefs on exceptions shall contain specific references to the pages of the record or exhibits which support arguments or allegations of error.

EFFECTIVE DATE: August 29, 1978.

FOR FURTHER INFORMATION CONTACT:

Robert L. Baum, Deputy General Counsel, 825 North Capitol Street NE., Washington, D.C. 20426, 202-275-4333.

SUPPLEMENTAL INFORMATION: Commission rules currently require that briefs on exceptions contain

"* * * appropriate references to the record and legal authorities." (18 CFR 1.31(b)). Despite this requirement many briefs on exceptions do not contain such references. This failure causes significant delays in Commission review of the briefs and in the writing of proposed orders for Commission action.

Accordingly, the Commission now amends its rules to include an express requirement that briefs on exceptions cite the pages of the record or exhibit that support the contentions made. Briefs that fail to comply with this requirement may be rejected or disregarded. The Director, Office of Opinions and Reviews, is authorized to require supplemental briefs in cases where briefs filed with the Commission do not conform to this requirement.

Since this rule deals with a matter of agency procedure and practice, notice and public procedure thereon is unnecessary pursuant to 5 U.S.C. 553(b). Moreover, because of the need to expedite Commission proceedings and because all parties to proceedings before the Commission will be given adequate time to file supplemental briefs in conformance with the requirement, the Commission finds that good cause exists for making the rule effective upon publication.

(Federal Power Act, as amended (16 U.S.C. 792 et seq.); Natural Gas Act, as amended (15 U.S.C. 717 et seq.); Interstate Commerce Act, as amended (49 U.S.C. 1 et seq.); Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267.)

In consideration of the foregoing, part 1 of title 18, Code of Federal Regulations, is amended as set forth below.

By the Commission.

Kenneth F. Plumb,
Secretary.

1. Section 1.31 is amended by revising clause (iv) of subparagraph (1) of paragraph (b) to read as follows:

§ 1.31 Exceptions to intermediate decisions, briefs; briefs and oral arguments before the Commission.

* * * * *

(b) *Nature and service of briefs on exceptions and of briefs opposing exceptions.* * * *

(1) * * *

(iv) the argument in support with references to the pages of the record or exhibits where the evidence appears. Briefs not in compliance with this requirement may be rejected or disregarded. The Director, Office of Opinions and Reviews is authorized to require supplemental briefs in cases where briefs filed with the Commission on and after the effective date of this amendment, do not conform to this requirement.

* * * * *

[FR Doc. 78-25178 Filed 9-7-78; 8:45 am]

[¶ 30,017A]

43 F. R. 40215 (September 11, 1978)

SUMMARY: The Commission amends its rules and regulations in order to establish a short-form hydroelectric license. In addition, a new application form is established with accompanying instructions for completing the application for a short-form license. The purpose of the rulemaking is to provide a simplified procedure and format for processing applications for small-scale water power projects that meet specific size criteria. Availability of such procedures would save time for the applicant and the Commission staff. It would eliminate obstacles to the development of small capacity water power projects in furtherance of national policies for conservation of fossil fuels.

DATES: The amendments are effective September 5, 1978.

FOR FURTHER INFORMATION CONTACT:

Ronald Corso, Office of Electric Power Regulation, 202-275-4863, Raymond Hagenlock, Office of the General Counsel, 202-275-4271.

The Federal Energy Regulatory Commission (Commission) gives notice that it is amending the General Rules and Regulations under the Federal Power Act, Subchapters A, B, and D, Chapter I, Title 18, Code of Federal Regulations. These amendments establish a short-form water power license (minor) and a new application form with accompanying instructions for completing the application for a short-form license (minor).

As stated in the notice of proposed rulemaking, 43 FR 18196 (April 28, 1978), the purpose of these amendments is to provide a simplified procedure and format for processing applications for small-scale water power projects. This procedure should save time for the applicant and the Commission staff, as well as to eliminate unnecessary obstacles to the development of small capacity water power projects, in furtherance of national policies for conservation of fossil fuels.[1]

The number of inquiries received by Commission staff in recent months concerning the installation of additional generating capacity at existing water power projects, the redevelopment of existing projects to provide additional power, and the installation of power generating facilities at existing non-power dams has increased sharply. This interest has been accompanied by a substantial increase in the number of applications filed with the Commission.

The proposed rulemaking would have imposed three eligibility criteria for a project to obtain a short-form license (minor). These were: (1) The project dam or diversion structure could be no more than 25 feet in height above stream bed; (2) the project could not impound a reservoir having a surface area of 10 acres or more; and (3) the project generating capacity could not exceed 2,000 horsepower (1,500 kilowatts). After examining the comments, reevaluating the criteria, and considering the legal and policy questions involved, the Commission has decided to eliminate the first and second limiting criteria to widen the applicability of the short-form license (minor) procedure to all projects having a generating capacity of 2,000 HP (1,500 kW) or less (that is, all "minor" projects).

In response to the notice, 18 entities and 1 individual submitted comments for Commission consideration.[2] The comments were generally favorable to the proposal, but most also expressed the view that the criteria used were far too restrictive, and should be expanded so that more applications could be processed under the streamlined procedure.

One common suggestion was that the generation limit be raised from 1,500 kW (1.5 MW) to 15 MW. The latter figure is the upper limit selected for the small hydroelectric project incentive program included in the National Energy Act now pending in Congress. These short-form license (minor) procedures are specifically intended to apply only to minor projects, those with installed capacity of 2,000 HP or less (i.e., 1.5 MW), for which the Commission may waive certain provisions of the Federal Power Act, as authorized in Section 10(i), 16 U.S.C. 803(i). But the Commission intends to simplify its hydroelectric licensing procedures for major projects as well. Its staff is currently reviewing these procedures and developing recommendations for the Commission's consideration. Thus, future rulemakings will propose additional simplified licensing procedures for major projects between 2,000 HP and 20,000 HP (15 MW), as well as for major projects larger than 20,000 HP, in generating capacity.

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[1] For example, the National Energy Act proposals now under consideration by a Joint Conference Committee of the United States Senate and House of Representatives include a program for loans, encouragement, and expeditious licensing for certain hydroelectric projects with no more than 20,000 HP (15 megawatts) installed capacity.

[2] Letters of comments were received from: Southern California Edison Co.; the Salt River Project; the New England Energy Task Force; the New England Regional Energy Advisory Board; the New England States Commissions; the National Rural Electric Cooperative Association; the Straflo Group; American Public Power Association; Central Vermont Public Service Corp.; LeBoeuf, Lamb, Leiby & MacRae; Power authority of the State of New York; Robert J. Taylor; the U.S. Department of the Interior, Heritage Conservation and Recreation Service; Central Maine Power Co.; Duke Power Co.; Maine Hydroelectric Development Corp.; the Mead Corp.; Allegheny Power Service Corp.; and Linton, Mields, Reisler & Cotton, Ltd.

Another suggestion common to many of the comments was that the height limitation be increased from 25 feet to 66 feet (20 meters). The higher figure is used by the Department of Energy in its Program Research and Development Announcement (PRDA), ET—78-D-07-1706. The 25-foot limitation was originally selected because it corresponded to the dam height set by Congress in the National Dam Inspection Act, 33 U.S.C. 467a–467e, as the upper limit for dams to be considered in a "low hazard" category. Comments generally pointed out that any size limitation based on safety reasons was irrelevant because at the time of licensing the Commission must find all dams safe and adequate, or capable of being made safe by taking appropriate action as spelled out in the licensing order and instrument. The Commission agrees and also notes that, for an existing but unlicensed project which is subject to our jurisdiction, the public health, safety, and welfare are better served by procedures which allow the swift issuance of a license for that project, but requiring the owner to take actions to make the project safe under penalty of law, than by a more cumbersome and lengthy licensing process required by a dam height limit. Thus, the Commission is eliminating the dam height criterion.

The final suggestion common to many of the comments was that the 10-acre reservoir size limitation was too restrictive. This limitation was based upon section 2 of the Fish and Wildlife Coordination Act (FWCA).[3] Upon further review, the Commission concludes that the consultation requirements of the FWCA will be satisfied by its solicitation of the relevant Federal and State agencies' comments by means of forwarding to those agencies a copy of the public notice of the application for license. The public notices, which are issued pursuant to the Federal Power Act,[4] will explicitly solicit comments. The Commission also notes that these Federal and State agencies are given a prior opportunity for comment and input on the proposed project very early in the process, because the short-form procedures require the applicant to consult with these agencies and include evidence of such consultation as part of the application submitted to the Commission. Furthermore, the agencies may obtain copies of the application from the Commission or the applicant upon request. Therefore, the Commission has decided to eliminate the criterion relating to reservoir size for projects that would otherwise be eligible for a short-form license (minor).

Finally, some comments suggested certain other changes in the new procedures—such as making them applicable to applications for relicensing and requiring only that a water quality certificate be applied for at the time of license application to this Commission, rather than be included with the short-form application. Those and other minor suggested changes have been made. In addition, the Commission is extending the new procedure to qualifying existing license applications already on file, as well as to future filings.

As a result of the changes discussed above, all existing "minor" license applications will be processed under the new short-form license (minor) procedures. Thus, the amendments to Commission regulations made below generally delete the existing sections dealing with "minor" licenses and substitute new sections for short-form licenses (minor). While some section numbers may thus be different from those in the notice of proposed rule making, the sections themselves are essentially the same.

The short-form license (minor) procedures in the notice of proposed rulemaking also contained proposed new forms L-22 and L-23, which were license order formats containing, inter alia, standard license articles. The expansion of the short-form license (minor) procedures to cover all minor projects obviates the need for any new forms. For standard license articles for short-form licenses (minor), the Commission will select the appropriate form from the current forms L-9, L-12, and L-14 through L-19 (revised October 1975) applicable to minor projects. (See 18 CFR 2.9 and Order No. 540, 40 FR 51998 (November 7, 1975).) For information, a typical format for a short-form license (minor) is attached as appendix A to this notice.

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[3] 16 U.S.C. 662.

[4] 16 U.S.C. 797 (e) and (f).

The Commission is making these amendments effective immediately. Because the amendments reduce the filing requirements in a certain type of application, they involve a substantive rule which relieves a restriction and are not required to be published 30 days prior to their effective date.

(Federal Power Act, as amended, 16 U.S.C. 792 et seq., Department of Energy Organization Act, Pub. L. 95-91, Executive Order 12009, 42 FR 46267)

For the reasons stated above, parts 3, 4, 16, and 131 of Chapter I, Title 18, Code of Federal Regulations, are amended as set forth below, effective immediately.

APPENDIX A

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

SHORT-FORM LICENSE (MINOR)

Before Commissioners:
[Applicant]

Project No. ——

ORDER ISSUING SHORT-FORM LICENSE

An application was filed on ——— and supplemented on ————— by ————— for a short-form license (minor) for a water power project.

[discussion, if any]

Issuance of a license for the project is in the public interest and in conformance with all applicable provisions of the Federal Power Act.

The Commission orders: (A) This license is issued to ————— (Licensee) of —————, for a period effective the first day of the month in which this order is issued, and terminating ——— for ["construction, operation, and maintenance" or "operation and maintenance", as suitable] of Project No. ——— located on —————, (a tributary of the —————,) subject to the terms and conditions of the Federal Power Act, insofar as not expressly waived here, which Act is incorporated by reference as part of this license, and subject to such rules and regulations as the Commission issues or prescribes under the provisions of the Act.

(B) This project consists of: (i) All lands constituting the project area and enclosed by the project boundary, to the extent of the licensee's interests in those lands. The project area and the project boundary are shown and described by certain exhibit K drawing(s), FERC No(s). ———, which also form part of the application for license.

(ii) Project works consisting of: [works listed] The location, nature, and character of these project works are more specifically shown and described by the exhibit cited above and by exhibit L drawing(s), FERC No(s). ———, which also form part of the application for license.

(iii) All of the structures, fixtures, equipment, or facilities used or useful in the maintenance and operation of the project and located in the project area, and any other property used or useful in connection with the project or any part of it; together with all riparian or other rights, the use or possession of which is necessary or appropriate in the maintenance or operation of the project.

The exhibits designated and described above in this paragraph (B) are approved and made a part of the license.

(C) Pursuant to section 10(i) of the Federal Power Act, it is in the public interest to waive the following sections of part I of the Act, and they are excluded from the license: 4(b), Except the second sentence relating to free access by the Commission or its agents to the project works and project records; 4(e), insofar as it relates to approval of plans by the Chief of Engineers and the Secretary of the Army; 10(c), insofar as it relates to depreciation reserves; 10(d); 10(f); 11; 12; 14, except insofar as the power of condemnation is reserved; 15; 16; 18, except as it relates to fishways; 19, 20; 21; 22; and 23(a), insofar as it relates to the determination of fair value.

(D) This license is also subject to the terms and conditions designated Articles 1 through ——— in Form L ——, entitled —————, attached to and made a part of this license. This license is also subject to these additional special terms and conditions:

[any special articles]

(E) This order shall become final 30 days from the date of its issuance unless an application for rehearing shall be filed as provided in Section 313(a) of the Federal Power Act, and failure to file such an application shall constitute acceptance of this license.

The acknowledgement of acceptance attached to this license shall be signed for the Licensee and returned to the Commission within 60 days from the date of issuance of this order.

By the Commission.

Secretary.

APPENDIX A

In testimony of (its) acknowledgement of acceptance of all of the terms and conditions of the foregoing order, (Name) ————, this —— day of ————, 19—, has caused his (its corporate) name to be signed hereto (by ———————— its President, and its corporate seal to be affixed hereto and attested by ————————, its ———————— Secretary, pursuant to a resolution of its Board of Directors duly adopted on the ———— day of ————, 19—, a certified copy of the record of which is attached hereto).

————————

(By ————————)

Attest:

————————

Secretary.

NOTE.—Execute in quadruplicate. Statements within brackets apply only to corporations, municipalities and associations of citizens.

[¶ 30,018]

43 F. R. 41965 (September 19, 1978)

PART 1—RULES OF PRACTICE AND PROCEDURE

CFR Correction

AGENCY: Federal Energy Regulatory Commission.

ACTION: CFR correction.

SUMMARY: This document makes technical changes to paragraph (c) of § 1.36 of Title 18 of the Code of Federal Regulations revised as of April 1, 1977. This correction is necessary because there are now two subparagraphs designated as (15).

FOR FURTHER INFORMATION CONTACT:

Lois Cashell, 202-275-4166.

In 18 CFR § 1.36(c), revised as of April 1, 1977, the second subparagraph numbered (15) should be corrected to read:

(16) Any reasonably segregable portion of a record after deletion of the portions which are exempt under this section.

The subparagraph numbered (16) should be renumbered as (17).

Dated: September 13, 1978.

KENNETH F. PLUMB,
Secretary.

[FR Doc. 78-26256 Filed 9-18-78; 8:45 am]

[¶ 30,019]

43 F. R. 46528 (October 10, 1978)

SUBCHAPTER A—GENERAL RULES

[Docket No. RM78-24]

PART 1—RULES OF PRACTICE AND PROCEDURE

Freedom of Information Act Requests and Appeals

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Commission's regulations implementing the Freedom of Information Act (FOIA) (5 U.S.C. 552) are revised to provide a uniform manner of addressing and marking FOIA requests and FOIA appeals with the Commission. The purposes of this revision is to insure expeditious handling, routing, consideration and disposition of FOIA requests and appeals within the Commission.

EFFECTIVE DATE: October 2, 1978.

FOR FURTHER INFORMATION CONTACT:

Herbert C. Rice, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, telephone: 202-275-4788.

SUPPLEMENTARY INFORMATION: The processing of Freedom of Information requests and appeals has been delayed in the past due to confusing designations on the documents or the envelopes in which they are enclosed. Requests for information or administrative appeals, taken pursuant to the FOIA, supra, require expeditious response by the Commission's staff. If initial requests for access to Commission records are not clearly labeled, they do not give the Staff adequate notice so that the documents can be forwarded to the appropriate office without delay for processing in accordance with statutory time limits.

This rulemaking addresses this problem by requiring all FOIA requests and appeals to be clearly marked as such. If the request or appeal is not clearly marked, the Commission's staff will mark it upon identification and immediately forward it to the appropriate office. In any event, initial FOIA requests for access to records shall be considered to be received upon actual receipt by the Director of Public Information; appeals from denials of request for access shall be considered to be received upon actual receipt by the Chairman of the Commission.

A general notice of proposed rulemaking has not been published for this rulemaking pursuant to 5 U.S.C. 553, et seq., because it is a rule of Commission procedure and practice and affects only the Commission's management. Pursuant to 5 U.S.C. 553, the rulemaking also will be effective as of the date of issuance since the rule affects only Commission practice or procedure, and management and personnel, and therefore does not abridge the effect of any requests or appeals filed pursuant to the regulations prior to amendment.

(Administrative Procedure Act, 5 U.S.C. 553; Freedom of Information Act, 5 U.S.C. 552.)

In consideration of the foregoing, it is proposed to amend § 1.36, part 1, chapter 1 of title 18, the Code of Federal Regulations, as set forth below.

§ 1.36 [Amended]

1. Section 1.36(f)(1) and (f)(2) are amended by designating the present subparagraphs as § 1.36(f)(1)(i) and (f)(2)(i) and adding new subparagraphs § 1.36(f)(1)(ii) and (f)(2)(ii) to read as follows:

* * * * *

(f) * * *

(1) * * * (i) * * *

(ii) Requests filed pursuant to this section shall be in writing, addressed to the Director of Public Information, and clearly marked "Freedom of Information Request". Any request for information received by the Commission not addressed and marked as indicated in this subparagraph will be so addressed and marked by Commission personnel as soon as it is properly identified and forwarded immediately to the Director of Public Information. Requests made pursuant to this paragraph shall be considered to be received, upon actual receipt by the Director of Public Information.

(2) * * * (i) * * *

(ii) Appeals filed pursuant to this section shall be in writing, addressed to the Chairman of the Commission, and clearly marked "Freedom of Information Appeals". Any such appeal received by the Commission not addressed and marked as indicated in this paragraph will be so addressed and marked by Commission personnel as soon as it is properly identified and forwarded immediately to the Chairman. Appeals taken pursuant to this paragraph shall be considered to be received, upon actual receipt by the Chairman.

* * * * *

By the Commission. Commissioner Holden dissenting.

(5 U.S.C. 552, 553.)

KENNETH F. PLUMB,
Secretary.

[FR Doc. 78-28525 Filed 10-6-78; 8:45 am]

[¶ 30,019A]

43 F. R. 47769 (October 17, 1978)

IMPORTATION AND EXPORTATION OF NATURAL GAS

Delegation of Functions by the Secretary of Energy to the Administrator of the Economic Regulatory Administration and the Federal Energy Regulatory Commission

AGENCY: Department of Energy.

ACTION: Notice of Delegations.

SUMMARY: Notice is hereby given of delegations by the Secretary of Energy to the Administrator of the Economic Regulatory Administration and to the Federal Energy Regulatory Commission respectively. The delegations convey authority to carry out functions vested in the Secretary under the Department of Energy Organization Act as those functions relate to approval or disapproval of applications to import or export natural gas pursuant to the Natural Gas Act and to build and operate border facilites for the import or export of natural gas pursuant to Executive Order No. 10485. The delegation orders are being issued in final form, but in view of the importance of these delegation orders to the administration of the Natural Gas Act and the implementation of the Department of Energy Organization Act, the public is requested to comment on them in writing. If the public comment demonstrates serious problems created by these delegations the Secretary will consider appropriate changes.

DATE: Written comments by November 13, 1978.

ADDRESS TO: Office of Public Hearing Management, Economic Regulatory Administration, Room 2313, Box TQ, 2000 M Street NW., Washington, D.C. 20461.

FOR FURTHER INFORMATION CONTACT:

Lynne H. Church, Division of Natural Gas Regulations, Economic Regulatory Administration, Room 3308, 2000 M Street NW., Washington, D.C. 20461, 202-632-4721.

Barry M. Smoler, Department of Energy, Office of General Counsel, 12th and Pennsylvania Avenue NW., Room 5116, Washington, D.C. 20461, 202-566-9380.

Brian J. Heisler, Federal Energy Regulatory Commission, Office of General Counsel, 825 North Capitol Street NE., Room 8100, Washington, D.C. 20426, 202-275-4341.

SUPPLEMENTARY INFORMATION:

I. Background.
II. Proposed delegation orders.
III. Proposed effective date and procedures for written comments.

I. BACKGROUND

The delegations relate to applications for approval to import or export natural gas under section 3 of the Natural Gas Act (NGA) and applications to build and operate border facilities for the import or export of natural gas pursuant to Executive Order No. 10485. The Secretary of Energy (Secretary) has the authority to approve or disapprove these applications under the Department of Energy Organization Act (DOE Act), Pub. L. 95-91, 42 U.S.C. 7101, et seq. (1977). Subsection 301(b) of the DOE Act transfers to, and vests in, the Secretary all the functions of the Federal Power Commission not specifically vested by the DOE Act in the Federal Energy Regulatory Commission (FERC). Included in the transfer to the Secretary are functions under section 3 of the NGA and Executive Order No. 10485. In addition, subsection 402(f) of the DOE Act explicitly reserves to the Secretary exclusive jurisdiction with respect to the regulation of exports and imports of natural gas.

The Secretary's authority to regulate imports and exports of natural gas may be "assigned" in whole or in part to the FERC under subsections 402(e) and (f) of the DOE Act. Furthermore, section 642 of the DOE Act allows the Secretary to "delegate" any of his functions to any officers and employees of the Department he may designate, which would include the FERC. The proposed delegation and assignment order to the FERC is based on both of these sections of the DOE Act.

The Secretary's authority to regulate imports and exports of natural gas originally was delegated to the Administrator of the Economic Regulatory Administration (the Administrator) on October 1, 1977 (Delegation Order No. 0204-4, para. 6, 42 FR 60726, November 29, 1977.) The Administrator currently has pending before him a number of applications to import or export natural gas. Some have been filed directly with the Economic Regulatory Administration (ERA) since it was activated on October 1, 1977, and others have been transferred to ERA after completion of certain procedures before the FERC. (DOE final rule of October 1, 1977, 42 FR 55534, October 17, 1977).

Many of the applications, particularly those to import liquefied natural gas (LNG), require consideration of numerous factors ranging from the effects of an import on U.S. balance of payments to the safety and environmental impact of the terminal facilities proposed to be built. Some of these considerations are specific to the individual applications and are representative of those areas traditionally within the expertise of the FERC's predecessor, the Federal Power Commission. Imports or exports of natural gas also raise significant policy question concerning the nation's security, degree of dependence on foreign supplies, effect of imports or exports on the American economy, and the impact of a particular import or export on national energy stategies.

II. The Delegation Orders

The delegation order to ERA and the delegation and assignment order to the FERC provide a mechanism whereby the Secretary, through his delegate, the Administrator, maintains authority over imports and exports of natural gas to the extent that they broadly concern energy policies on an international, national and interregional scale. Those functions involving the continuing supervision of each of the interstate natural gas pipeline companies would rest within the FERC's jurisdiction.

More specifically, the delegation to the Administrator, which amends Delegation Order No. 0204-4, would allow him to determine whether a proposed import or export of natural gas is not inconsistent with the public interest within the meaning of section 3 of the NGA, based on certain considerations which may include (1) the security of supply, (2) the effect on the U.S. balance of payments, (3) the price proposed to be charged at the point of importation or exportation, (4) national and regional needs for the natural gas to be imported or exported, and (5) in the case of imported natural gas, the eligibility and respective shares of purchasers and participants. In addition, the Administrator would be authorized to determine whether the proposed import or export is consistent with the Department's regulations or statements of policy specifically applicable to natural gas imports and exports. An example would be any statement of policy on the import of LNG which the Department may adopt in accordance with section 301 of the DOE Act.

In considering those aspects of an import or export application within his jurisdiction, the Administrator would also be authorized to attach terms and conditions which he determines to be necessary to make the import or export not inconsistent with the public interest. For example, the Administrator could condition his determination that a proposed import meets the standard of section 3 of the NGA with a requirement that the importer and his foreign supplier change the terms of the import contract with respect to initial price, or duration, or price changing clauses.

Finally, the delegation to the Administrator reserves to the Secretary the right to directly administer the functions vested in him if he deems it necessary or appropriate to do so.

The delegation order to the FERC authorizes it to exercise all other functions under section 3 of the NGA which are not delegated to the Administrator and which have not been previously exercised by him, as well as all functions under sections 4, 5 and 7 of the NGA insofar as authority under those sections may otherwise have been vested in the Secretary. Thus, the FERC would have the authority to approve or disapprove the siting, construction, and operation of particular facilities and the place of entry of imported natural gas. The Administrator would be able to disapprove the siting, construction and operation of particular facilities or the selection of a place of entry only in the implementation of Department regulations or statements of general policy, or on the basis of considerations of the security of supply or the effect on U.S. balance of payments.

Further, under the delegations, if an importer proposed to sell natural gas in interstate commerce for resale, the FERC would review the prices under the public convenience and necessity standard of section 7 of the NGA and the just and reasonable standard of sections 4 and 5 of the NGA. The FERC might thereby disapprove a natural gas company's charging of rates based on import prices sanctioned by the Administrator. It should also be noted that the Commission itself would determine the applicability of sections 4, 5 and 7 of the NGA in a particular case, subject only to judicial review.

The FERC is delegated and assigned the function of issuing whatever orders, authorizations and certificates as are necessary or appropriate to implement the respective determinations made by the Administrator (to the extent that he determines a proposed import or export is not inconsistent with the public interest) and by the FERC. The delegation order requires that any authorization of an import or export issued by the FERC under section 3 of the NGA must include any terms and conditions previously attached by the Administrator, although the FERC would not be required to authorize an import or export if it determined that the application, as conditioned by the Administrator, is inconsistent with those provisions of the NGA vested in the FERC to administer or which have been delegated or assigned to the FERC to administer.

The mechanism set up in the delegations would apply to all natural gas import and export applications initially submitted to the ERA on or after October 1, 1977, or which were transferred to the Secretary or the Administrator pursuant to the Final Rule dated October 1, 1977, with the following exceptions:

a. Those cases initially pending before the Federal Power Commission and transferred in their entirety by rule to the FERC at the time the Department was activated (10 C.F.R. 1000.1(d); 42 FR 55534, October 17, 1977); and

b. Those functions already delegated by the Secretary to the FERC in DOE Delegation Orders No. 0204-1 (certain functions under the NGA not directly related to imports and exports of natural gas except for cases specifically assigned to the FERC by rule), No. 0204-8 (relating to the approved Alaskan natural gas transportation system) and No. 0204-14 (certain aspects of *Distrigas of Massachusetts Corp., et al.*, ERA Dockets No. 77-007-LNG and No. 77-011-LNG which have not already been decided by the ERA Administrator).

In addition, the mechanism would not apply to ERA Docket No. *77-001-LNG, Pacific Indonesia LNG Co., et al.*, which is in the rehearing stage. The Administrator would continue to exercise final decisional authority under section 3 of the NGA and Executive Order No. 10485.

Following is an example of how the proposed delegation would operate:

Assume Applicant A proposed to import liquified natural gas (LNG) at port X and to construct docking, storage and regasification facilities. A also proposed to resell the regasified product to B for resale in the interstate market. Applicant A would simultaneously file with both ERA and the FERC complete applications for the importation of the LNG, the construction of facilities and the resale of the gas. At the same time B would file a section 7 application with the FERC. If A's application involved a major federal action significantly affecting the quality of the human environment within the meaning of the National Environmental Policy Act, 42 U.S.C. 4321 *et seq.*, ERA would prepare or arrange for the preparation of an environmental impact statement on the project.

The ERA would proceed to obtain the necessary information and hear argument on those issues it would decide. These would include, at a minimum, the security of A's supply, whether the price A would pay at the point of importation or some earlier point is appropriate, whether A's division and direction of the gas to B in the first instance properly reflect national policy and national energy needs, and whether the import is otherwise consistent with Department policy.

If, after hearing, the Administrator decided on the basis of functions delegated to him that the import is not consistent with the public interest, he would deny the application outright. The applicant could then exercise the rights under section 19 of the NGA to apply to the Administrator for rehearing and to the appropriate United States Court of Appeals for judicial review. On the other hand, if the Administrator decided the application favorably on the basis of those considerations within his jurisdiction, he would issue a determination to that effect to the parties and to the FERC. The Administrator's decision approving an application might contain certain conditions to assure that the project is constructed and operated consistent with the terms of the approval. For example, the order could condition approval of A's renegotiating a price with its supplier that does not exceed a specified level.

Upon issuance of a favorable determination by the Administrator, the FERC's formal proceedings would begin and would include, among other things, consideration of any pipeline facilities to be constructed by A or B, the transportation rates, and the justness and reasonableness of the prices proposed to be charged the distribution companies. If the FERC determined to approve the applications, based upon the considerations within its jurisdiction, it would issue an order implementing both its own and the Administrator's determinations. The order would include all the terms and conditions previously imposed by the Administrator. However, if the FERC found, for example, that the import price as proposed to be flowed through would result in a particular tariff's either being unjust and unreasonable within the meaning of section 4 of the NGA or being contrary to the public convenience and necessity under section 7 of the NGA, it could not change the contract and pricing conditions imposed by the Administrator, but could deny the application entirely or impose additional requirements consistent with the Administrator's conditions. Rehearing before the FERC of the FERC's determination would be available at this point.

These delegation orders will be implemented through the promulgation of procedural regulations by ERA and the FERC. These regulations, which will be available for public comment prior to adoption, will be designed to expedite, to the extent possible, the Administrator's and the FERC's final decisions in natural gas import and export cases, while still providing all interested parties with an opportunity to submit evidence and views to both the Administrator and the FERC, as appropriate.

III. EFFECTIVE DATE AND PROCEDURES FOR WRITTEN COMMENTS

The delegation orders are effective upon publication.

Delegation orders are internal agency organizational rules and typically are not made available for public comment. However, in view of the importance of these delegations to the administration of the Natural Gas Act and the implementation of the DOE Act, the public is invited to submit views, data or arguments with respect to the orders. If public comment indicates that these delegation orders create substantial problems in the administration of the NGA in import and export cases, the Secretary will consider making appropriate changes. Comments should be submitted to the address indicated above in this notice and should be identified on the outside envelope with the designation "Delegations by the Secretary of Energy Regarding the Importation and Exporation of Natural Gas." Thirty copies should be submitted. All comments received by November 13, 1978 will be considered in evaluating the delegation orders. All comments received will be available for public inspection in the DOE Reading Room, Room 2107, Federal Building, 1200 Pennsylvania Avenue NW., between the hours of 8 a.m. and 4:30 p.m., Monday through Friday.

Any information or data considered to be confidential must be so identified and submitted in a single written copy. We reserve the right to determine the confidentiality of the information or data and to treat it according to our determination.

These delegations are procedural only, and the requirement in section 7(c)(1) of the Federal Energy Administration Act of 1974, Pub. L. 93-275, as amended, that proposals "affecting the quality of the environment" be reviewed by the Environmental Protection Agency prior to issuance is therefore not applicable.

(Department of Energy Organization Act, Pub. L. 95-91; E.O. 12009, 42 FR 46267.)

Issued in Washington, D.C. on October 10, 1978.

[¶ 30,020]

43 F. R. 48992 (October 20, 1978)

[Docket No. R-441]

PART 2—GENERAL POLICY AND INTERPRETATION

Modification in Finding Clause (1) of Order No. 455-C Issued May 19, 1978

AGENCY: Federal Energy Regulatory Commission.

ACTION: Order denying requests for clarification, rehearing, and reconsideration and modifying order No. 455-C.

SUMMARY: In 1972 the Commission issued order No. 455 which established optional procedures for certificating new producer sales of gas. Order No. 455 was subsequently amended by order No. 455-C in May 1978. The subject regulations which was contained in § 2.75 relate to the collection of contract rates from customers for deliveries of natural gas at no higher than the prevailing nationwide rate. The Commission received petitions asking for clarification, rehearing and reconsideration of order No. 455-C. This order denies requests for clarification, rehearing, and reconsideration and also modifies the language in finding clause No. (1) of order No. 455-C issued by the Commission on May 19, 1978.

EFFECTIVE DATE: Effective on date of issuance.

FOR FURTHER INFORMATION CONTACT:

Elizabeth Pendley, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, 202-275-4216.

ORDER DENYING REQUESTS FOR CLARIFICATION, REHEARING, AND RECONSIDERATION AND MODIFYING ORDER No. 455-C

OCTOBER 11, 1978.

On June 16, 1978, Ecee, Inc., Pinto, Inc., Vsea, Inc., Texas Production Co., and TBP Offshore Co., and on June 19, 1978, POGO Producing Co. and Pennzoil Oil & Gas, Inc. (hereinafter collectively referred to as Petitioners) filed for clarification, rehearing, and reconsideration of order No. 455-C, pursuant to section 19(a) of the Natural Gas Act and § 1.34 of the Commission's [1] rules of practice and procedure.

ALLEGATIONS OF PETITIONERS

Petitioners contend that the Commission did not comply with the mandatory requirements of the Administration Procedure Act [2] nor did "good cause" [3] exist to waive said requirements. Further, Petitioners allege that order No. 455-C is void as the Commission did not comply with the DOE Act. Petitioners contend that said Act obligates "the Commission (to) give notice of and have a hearing on any rulemaking which relates to the establishment of rates and charges under the Act." [4] Petitioners contend that order No. 455-C will weaken optional procedure as a viable alternative mechanism, will create rate uncertainty by instituting an "open ended" period of collecting a rate which might be below that later found to be just and reasonable, and will exceed the Commission's statutory authority by instituting a retroactive rate increase.[5] Petitioners also contend that the issuance of order No. 455-C does not comply with the Sunshine Act.[6]

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[1] Prior to Oct. 1, 1977, the "Commission" refers to the Federal Power Commission; subsequent thereto, it refers to the Federal Energy Regulatory Commission.

[2] 5 U.S.C. 553.

[3] 5 U.S.C. 553(b)(B).

[4] Petition of Ecee, Inc., Pinto, Inc., Vsea, Inc., Texas Production Co., and TBP Offshore Co., for rehearing and reconsideration of order No. 455-C, p. 3.

[5] Application of POGO Producing Co., and Pennzoil Oil & Gas, Inc., for clarification, rehearing, and reconsideration, pp. 2 and 3.

BACKGROUND

In 1972 the Commission issued order No. 455 [7] which established the optional procedure for certificating new producer sales of natural gas. Optional procedure, § 2.75: (1) Permits the producer to request approval of contracts at rates that may exceed the maximum authorized by the applicable rate order; (2) allows the Commission to determine in a single proceeding whether "the public convenience and necessity" warrants the issuance of a certificate and whether the rates requested are "just and reasonable"; (3) allows the Commission to issue a permanent certificate which upon acceptance by the producer is not subject to change under section 4 of the Act; (4) allows the producer to collect these rates without risk of refund obligations; and (5) provides an abandonment assurance, if authorized, at the end of the contract term.[8]

Originally, paragraph (o) of § 2.75 permitted producers, 6 months after the commencement of deliveries, to collect their contract rate without any refund obligation until such time as a final order was issued by the Commission. Subsequently, the 6-month provision was extended to 9 months.[9] The Commission reasoned that "the public interest requires a disposition of the certificate applications under the optional procedure * * * prior to the effectuation of a nonrefundable contract rate." [10]

ORDER NO. 455-C

On May 19, 1978, the Commission further revised paragraph (o) of § 2.75 by again extending the time period for analysis.[11] Section 2.75(o) now states that upon determining that a final decision would not be reached by the Commission within the 9-month period, the Commission may extend the analysis period until a final order is issued. During the extended period, deliveries would continue to be made at rates no higher than the prevailing nationwide rate. Also, the revision provided for a surcharge to be recouped by the applicant if the final order established a just and reasonable rate in excess of the nationwide rate collected during the extended period. These revisions of § 2.75(o) became effective upon issuance of the Commission order.

COMPLIANCE WITH THE ADMINISTRATIVE PROCEDURE ACT

Petitioners contend that the Commission ignored the mandatory rulemaking procedure set by the Administrative Procedure Act (APA) which delineates a general notice of proposed rulemaking,[12] an opportunity for public participation or comment,[13] and publication of the rule at least 30 days prior to its effective date.[14] Although the commission acted under a finding of good cause [15] which waives the procedural rulemaking steps, Petitioners contend that good cause did not exist and that the order violates the APA rulemaking procedure. Further, Petitioners state that jurisprudence requires more than an agency's bare allegation of "good cause" to justify its dispensing with normal procedures, and that any exception must be strictly scrutinized.

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[6] Id. at 9; Sunshine Act, 5 U.S.C. 552(b).

[7] Order No. 455, Optional Procedure for Certificating New Producer Sales of Natural Gas, 48 FPC 218 (1972), affirmed in part and reversed in part sub nom., *Moss* v. *F.P.C.*, 502 F. 2d 461 (D.C. Cir. 1974), reversed in part, 424 U.S. 494 (1976).

[8] 18 CFR 2.75; 424 U.S. at 497, 598.

[9] In the Pennzoil Louisiana and Texas Offshore Co., Inc., et al., order issued May 8, 1978, in docket Nos. CI77-702, et al., the applicable time period ran 9 months from the date the Commission was notified of commencement of deliveries as required by sec. 2.75(n).

[10] Order No. 455-B, Amendment of Statement of Policy Relating to Optional Procedure for Certificating New Producer Sales of Natural Gas, issued Nov. 25, 1974, in docket No. R-441.

[11] Order No. 455-C, Further Amendment of Statement of Policy Relating to Optional Procedure for Certificating New Producer Sales of Natural Gas, issued on May 19, 1978, in docket No. R-441.

At the time order No. 455 was issued, the Commission reiterated its responsibility to assure reliable and adequate supplies at the lowest reasonable costs to the consumers of natural gas.

> To this end, we seek to provide two incentives to domestic production, both fully congruous with consumer protection. First, we will certificate sales of gas not previously deliverable to the interstate market at prices which are shown to be in the public interest. Second, to the extent possible, we will lessen rate uncertainty which has prevailed since the early 1960's.[16]

Further, the Commission delineated its reasoning with regard to the 6-month period of analysis.

> Such a limitation is, however, a reasonable one, since predicated on the assumption that the Commission will have acted by final order within that period of time * * * 6 months is clearly an adequate period for preliminary Staff analysis and review of applications tendered under the optional procedure. Accordingly, by action to deny or condition certificates prior to the expiration of the 6-month period, we can protect against the impact of a nonrefundable rate which is not just and reasonable.[17]

During the 6 years from issuance of order No. 455 to its revision in order No. 455-C, the applications requesting optional procedure have become more complex requiring lengthy detailed analysis, and additional information. As well, the contract rate sought has increased dramatically during this time period with producers now seeking to collect substantially higher rates. It has long been recognized that the Commission has the flexibility to adapt its policies to changing circumstances.[18]

Obviously, the consequences of allowing producers to automatically collect their contract rate no matter how high at the expiration of the 9-month period imposes a substantial hardship for the consumer. This would be true even if producers were required, as they were not under order Nos. 455, 455-A and 455-B, to make refunds of amounts collected at the expiration of the 6- to 9-month period in excess of the just and reasonable rate.

As we stated in order No. 455-C:

> The Commission cannot permit consumers to go unprotected during the period of analysis and administrative proceedings necessary to determine the public interest and the necessity of allowing sales of gas at prices substantially in excess of the nationwide norm.[19]

The Administrative Procedures Act recognizes two exceptions to notice and public participation: One is for general statements of policy; the other is for a good cause finding that the procedure is impracticable, unnecessary or contrary to the public interest. The Commission utilized the latter exception.

The Commission did not peremptorily stamp "good cause" on the issuance of order No. 455-C; rather, in compliance with the Administrative Procedure Act, the Commission delineated its good cause findings that notice and public procedure were contrary to the public interest. The Commission stated that it was "concerned that a delay in the effective date of this rule until after public comment would trigger a flood of applications during the comment period from producers wishing to collect contract rates after the 9-month period without refund obligation." [30] The Commission feared that "Such a result would defeat the Commission's purpose of protecting consumers from the economic burden of nonrefundable rate collections in excess of the just and reasonable rate." The Commission feared that it would be so overwhelmed "with § 2.75 applications that existing as well as new applications could not be processed within the 9-month period. [31]

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[12] Administrative Procedure Act, 5 U.S.C. 553(b).

[13] Administrative Procedure Act, 5 U.S.C. 553(c).

[14] Administrative Procedure Act, 5 U.S.C. 553(d).

[15] Administrative Procedure Act, 5 U.S.C. 553(b)(B)

* * * when the agency for good cause finds (and incorporates the finding and a brief statement of reasons therefor in the rules issued) that notice and public procedure thereon are impracticable, unnecessary, or contrary to the public interest.

[16] Order No. 455, Mimeograph at 3.

[17] Order No. 455, Mimeograph at 24.

[18] *Permian Basin Area Rate* cases, 390 U.S. 747 at 800, 816 n. 99; *Wisconsin* v. *F.P.C.*, 373 U.S. 294, 309 (1963); *F.P.C.* v. *Natural Gas Pipeline Co.*, 315 U.S. 575, 586 (1942).

[19] Order No. 455-C, Mimeograph at 4.

COMPLIANCE WITH DOE ACT

Petitioners contend that the order No.455-C, issued under the "good cause" exception to APA rulemaking regulations is void under section 403(c) of the DOE Act. Section 403(c) provides: "Any function described in section 402 of this Act which relates to the establishment of rates and charges under the Federal Power Act or the Natural Gas Act, may be conducted by rulemaking procedures. Except as provided in subsection (d), the procedures in such a rulemaking proceeding shall assure full consideration of the issues and an opportunity for interested persons to present their views." Section 403(c) has no applicability to order No. 455-C because the Commission was not, in that order, establishing rates. Rather, the Commission was changing certain requirements regarding the time periods for which rates could be collected as well as provisions regarding refunds and surcharges. The rates which would be subject to the order would be established in separate proceedings under the optional procedure provisions of the Commission regulations.

Moreover section 403(c) is not the exclusive authority for the Commission's rulemakings, nor was it relied on in the issuance of the order. With respect to its authority to issue rules, the Commission in order No. 455-C, cited section 16 of the Natural Gas Act and section 401(a) of the Department of Energy Act. Both of these sections authorize the Commission, without qualification, to issue rules and regulations necessary to carry out its functions. Accordingly, it is the Administrative Procedure Act which governed order No. 455-C. As pointed out above, the Commission has complied with that Act.

RATE CERTAINTY

We agree that, at least for the period after the expiration of the 9-month period and prior to the Commission's determination of the just and reasonable rate, the provisions of order No. 455-C will diminish, for a period of time, the assurance to producers of the exact amount of revenues that they may retain. However, since throughout this period the producer will be authorized to keep the amount ultimately determined to be the just and reasonable rate, any asserted rate uncertainty does not really exist within the normal regulatory context. In any event, even if we were to accede to the producer's argument that rate certainty is a significant factor, it must be balanced against a need to adequately protect the consumer against unreasonable charges. The purpose of order No. 455-C was to strike a fair balance between these factors.

Petitioners' concern that our order violates the prohibition against retroactive ratemaking is misplaced. If the 9-month period is extended by us, the collection of the national ceiling rate will involve the collection of a tentative rate, which it is recognized, will be subject to upward adjustment in the event the just and reasonable rate is determined to be higher. It is thus the conditional nature of the rate which takes it out of the posture of retroactive ratemaking. We believe this procedure to be essentially the same as that followed when a producer collects an above ceiling rate, subject to refund. The difference in procedure is that the consumer is not required to pay above ceiling rates pending the Commission's determination, and this is particularly important when the contract is substantially above the ceiling and the volumes are large. Furthermore, our procedure obviates the difficulties involved in the trickling down of refunds to consumers.[32]

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[30] During an en banc hearing before the Commission on June 19, 1978, a witness for United alluded to a sense of urgency on the part of PLATO to avoid a Commission order which would change § 2.75 as one of the reasons for filing the optional procedure petition hurriedly on May 17, 1978. Commission in en banc hearing in *Pennzoil Louisiana and Texas Offshore Co. Inc.*, docket Nos. CI78-767, CI77-702, CI78-499, CI78-501, et al., June 19, 1978, transcript pp. 354, 365-366, 368, 370-371, 372-373, 375.

[31] Order No. 445-C, Mimeograph at 6.

COMPLIANCE WITH THE SUNSHINE ACT

Petitioners question the Commission's compliance with the Sunshine Act [33] in the following manner: "To the best knowledge of Applicants, the Commission did not adopt this order during an open meeting as required by the Government in the Sunshine Act, 5 U.S.C.A. 552b, and its own regulations, 18 CFR 1.3a." [34]

In fact, the Secretary of the Commission issued a notice of the meeting on the afternoon of May 19, 1978, in accordance with the Sunshine Act. The meeting was held at 2 p.m., May 19, 1978, in the Commission meeting room, and was, in compliance with the Act, open to the public. The Commission's actions in this matter were in compliance with the Sunshine Act.

MODIFICATION OF ORDER No. 455-C

The Commission has determined to modify the language of finding clause (1) order No. 455-C to more accurately portray the Commission's position in this matter.

The Commission orders: (A) The requests for clarification, rehearing, and reconsideration filed by Petitioners on June 16, 1978, and June 19, 1978, respectively, are hereby denied based on reasons set forth herein.

(B) The language in finding clause (1) has been modified to read as follows:

> Good cause exists to issue this amendment without notice and public procedure. It is contrary to the public interest to provide for notice and public procedure because to do so would deter the Commission's efforts to protect consumers against the collection by producers of rates in excess of the national ceiling rate, without refund obligation and would delay the protection consumers are required to receive under the Natural Gas Act.

By the Commission.

KENNETH F. PLUMB,
Secretary.

[FR Doc. 78-29564 Filed 10-19-78; 8:45 am]

[¶ 30,020A]

43 F. R. 50167 (October 27, 1978)

[6740-02-M]

Title 18—Conservation of Power and Water Resources

CHAPTER I—FEDERAL ENERGY REGULATORY COMMISSION

PART 154—RATE SCHEDULES AND TARIFFS

Modification of Purchased Gas Cost Adjustment Clause Regulations

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule (order No. 13 issued in docket No. R-406).

SUMMARY: This order amends the Federal Energy Regulatory Commission's purchased gas cost adjustment (PGA) clause regulations to limit to two a year the number of purchased gas cost adjustment rate filings an interstate pipeline may make and to allow these pipelines to accrue and collect carrying charges on amounts carried in their deferred purchased gas cost accounts. The number and frequency of PGA filings caused by constantly rising costs have reached such magnitude that they impose an undue financial and administrative burden on all affected parties. The rule is intended to relieve that burden.

[The next page is 30,091-3.]

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[32] *F.P.C.* v. *Tennessee Gas Transmission Co.*, 371 U.S. 145, 154 (1962).

[33] Sunshine Act, 5 U.S.C. 552b; order No. 562, Order Adopting Rules Governing Observation of Commission Meetings and Ex Parte Communications, issued Mar. 11, 1977, in docket No. RM77-4.

[34] Joint Application for Clarification, Rehearing, and Reconsideration, filed on June 19, 1978, in docket No. R-441 by Applicants, POGO producing Co. and Pennzoil Oil & Gas, Inc.

EFFECTIVE DATE: January 1, 1979.

FOR FURTHER INFORMATION CONTACT:

Charles E. Bullock, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D. C. 20426, 202-275-4232.

SUPPLEMENTARY INFORMATION:

BACKGROUND

Section 154.38(d) of title 18 of the Code of Federal Regulations (CFR), permits natural gas pipeline companies to include a purchased gas adjustment provision (PGA clause) in their FERC gas tariffs under certain specified conditions. The Federal Power Commission (FPC) initially decided to permit PGA clauses in order to avoid frequent consideration of rate increase filings caused by constantly rising costs of purchased gas. It now appears that the number and frequency of PGA filings have reached such magnitude that they impose an undue financial and administrative burden upon the pipeline companies, their customers, the staff of the Federal Energy Regulatory Commission (Commission), the State commissions, and the ultimate consumers.

On May 10, 1976, the FPC[1] issued a notice of proposed rulemaking, docket No. R-406, which proposed to limit the number of filings of future PGA clause rate changes to two per year, and prescribe semiannual filing dates for each pipeline company. The proposal was intended to relieve all affected parties of the tremendous burden created by the current system of PGA filings. Recognizing that the semiannual limitation would force pipeline companies to carry larger balances of deferred purchased gas costs, the Commission also indicated that it would consider rate base treatment or carrying charges for the deferred amounts.

In response to requests for reconsideration of the assigned dates, a conference was held on January 11, 1977. A revised schedule of semiannual effective dates was established.[2] On April 26, 1977, a notice for further comments was issued. Comments were due by May 11, 1977. Nine parties filed comments at that time.

SUMMARY OF COMMENTS

A total of 47 parties filed comments to the notice of proposed rulemaking and the notice for further comments. All but a few supported the limitation to two filings per year. More than half of the commentators that expressed support for the proposal indicated, however, that they could not support it unless carrying charges for the deferred balances were allowed. Most of the commentators further indicated that:

(1) Carrying charges rather than rate base treatment should be adopted for any deferred balance; and

(2) Exceptions from the semiannual filing limitation should be allowed so that purchasing pipelines can simultaneously track general section 4(e) filings of their pipeline suppliers and changes in the cost of Canadian gas.

The Interstate Natural Gas Association of America (INGAA) supports carrying charges over rate base treatment for the following reasons:

(1) A carrying charge is fair because it is computed on the actual deferred balance;

(2) The pipeline is protected because it receives reimbursement for the substantial carrying costs it incurs;

(3) The pipeline customers are protected because the carrying charge is computed on the actual amount carried and the customers receive credit for interest if overcollections result;

(4) This method is easier to administer.

INGAA opposes rate base treatment because of the difficulty in accurately projecting the balance in the deferred account and the regulatory lag involved.

Many commentators suggested specific methods of allowing carrying charge rates. The suggestions included allowing carrying charges equal to:

(1) The rate of return included in the effective rate of the pipeline;

(2) The short-term borrowing rate available to the pipeline in the then current borrowing market; or

(3) The interest rate on amounts to be refunded that is prescribed by the Commission.

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[1] This proceeding was commenced before the FPC. By the joint regulation of October 1, 1977 (10 CFR 1000.1), it was transferred to the FERC. The term "Commission" when used in the context of action taken prior to October 1, 1977, refers to the FPC when used otherwise, the reference is to the FERC.

[2] See new § 154.38(d)(4)(iv)(a).

The American Public Gas Association (APGA) favored the two filings per year proposal but opposed any form of relief on the deferred balances. APGA argues that PGA clauses deviate from the general ratemaking principle that a utility not be permitted to reflect an increase in one item of cost without reviewing that utility's other costs and its total revenues. Thus, APGA states the "two a year" proposal should be adopted because it limits the alleged deviation of the PGA clause from the aforementioned ratemaking principle. However, for the same reason (i. e., the deviation), APGA argues that carrying charges should not be adopted because they further aggravate the problems purportedly caused by PGA clauses.

The notice of proposed rulemaking included a suggestion that supplier pipelines should make extra efforts to provide information on proposed rate levels to their purchasers who must make concurrent PGA filings. One commentator expressed the opinion that this suggestion should be incorporated as a requirement.

The proposal was opposed by one commentator. That commentator stated that implementation of the proposal would concentrate purchased gas costs during certain periods and cause an intensified impact on the consumer. The commentator also states the proposal would result in an inequitable distribution of costs among customers since the proposal would allow the gas to be used in one season and paid for in the next. Finally, the commentator states that the proposal would create a financial burden on intermediate pipelines.

Several commentators originally expressed concern with the suggested schedule of effective dates. The January 11, 1977, conference was held in response to this concern and a revised schedule was subsequently adopted to incorporate the suggestions made in the meeting.

FINDINGS OF THE COMMISSION

The Commission finds that due to the higher number of PGA filings it is receiving and processing, pipeline companies should be limited to two PGA filings annually, pursuant to the attached schedule in appendix A, and that carrying charges should be allowed. The Commission is not persuaded that implementation of this rule will result in inequitable distribution of purchased gas costs among a pipeline's customers. To the contrary, by reducing the number of PGA filings the rule should tend to result in a more equitable distribution of costs.

The parties' argument that carrying charges are preferable to rate base treatment of the deferred account are persuasive. While the Commission has allowed a number of pipeline companies carrying charges, these were allowed only in individual rate cases where a strong showing was made in support thereof. The support included a showing of large and recurring deferred balances. The Commission's experience gained during the 6 years PGA clauses have been permitted in pipeline company tariffs indicates that carrying charges should be provided for deferred purchased gas balances for all interstate pipelines. For example, deferred purchased gas costs recorded by major class A and B companies at the end of calendar year 1972 through 1976 are as follows: (1) 1972—$22,470,000; (2) 1973—$137,244,000; (3) 1974—$226,434,000; (4) 1975—$116,956,000; and (5) 1976—$570,050,000.[3]

Additionally, the 1977 form 2's of the 18 largest companies indicate recorded deferred purchased gas cost balances at December 31, 1977, of $558 million. The rapid buildup in these balances over the 6-year period, especially balances in excess of one-half billion dollars the last 2 years, indicates a substantial economic burden on the industry. Fairness dictates that some form of compensation be permitted on the deferred balances. The carrying charges shall be limited to the charge prescribed for interest on refunds under § 154.67(c).

In response to the APGA comments discussed previously, neither the PGA clause itself nor the carrying charge proposal violates the principle that rate adjustments must be premised upon a showing that all costs rather than just one item of cost justify the rate adjustment.[4] For example, § 154.38(d)(4)(vi) requires a cost of service review of the pipeline's overall rates at least every 3 years. In addition, given the large increases in purchased gas costs which have flowed through the various PGA clauses since 1972, it is very probable that, absent the PGA clause, this Commission's dockets would have been clogged with numerous general section 4 pipeline rate filings made pursuant to

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[3] Statistics of Interstate Natural Gas Pipeline Cos. 1976, p. 28.

[4] See order No. 452 (issued April 14, 1972, in docket No. R-406).

§ 154.63 as pipelines attempted to protect themselves against possible undercollections due to increasing purchased gas costs. Thus, contrary to the implication contained in APGA's comments, PGA clauses have been of benefit to pipelines and consumers. However, in spite of the PGA clause's avowed purpose to insure dollar for dollar collection of PGA costs, pipelines have experienced large amounts of undercollections being accrued in the deferred account which are recoverable, after a delay, by way of subsequent surcharges. Given the benefits of the PGA to all concerned, and given the financial problems that could result to pipelines as their balances increase due to changes in purchase pattern, as well as the impact of the "two a year" proposal adopted in this order, we find again that the carrying charges proposed in this order are sound regulatory practice and should be adopted.

The Commission recognizes that the deferral of purchased gas cost creates a timing difference between the period during which the gas cost enters into the determination of taxable income and the period during which the cost enters into the determination of pretax book income. This timing difference has the effect of reducing a company's net outlays for unrecovered gas costs when the Account 191 balances are positive and conversely increasing its outlay for income taxes when the Account 191 balances are negative. Accordingly, in compliance with the provisions of FPC Orders 530 (40 FR 26987) and 530B, we shall therefore require that in order for a company to be eligible for carrying charges, the company adopt the principles of interperiod income tax allocation in connection with balances recorded in the unrecovered purchased gas cost account with the resulting tax effects to be recorded in Account 283, Accumulated deferred income taxes—Other, or Account 190, Accumulated deferred income taxes, as appropriate, in accordance with the provisions of those accounts (18 CFR Parts 201 and 204). The carrying charges shall be computed monthly on the net balances in Account 191 and the related amounts in Account 283 or 190 as appropriate as of the end of the immediately preceding month.

The Commission also finds that there should be no exceptions to the two PGA filings per year limitation. Allowing exceptions would increase the frequency of PGA filings and would reduce the effectiveness of this rulemaking. While some cash-flow problems may occur to those companies carrying large deferred balances, the implementation of carrying charges should effectively compensate pipelines for the time value of the amounts carried in the deferred account and thus protect the financial integrity of the pipeline. It is appropriate, at this point, to refer to a proposed rulemaking, in docket No. RM79-1 (published elsewhere in today's issue) which, if adopted, would require pipelines to elect to reflect changes in purchased gas costs either through a PGA clause, or through general rate filings made pursuant to § 154.63. The purpose of the proposal is to limit the ways that purchased gas costs can be recovered. If a pipeline elects to adopt or maintain a PGA clause, it will be precluded from reflecting changes in purchased gas costs in a general rate adjustment filing pursuant to § 154.63. The election will be for 3 years unless the pipeline can demonstrate good cause, as described more fully in the notice, to justify the grant of a waiver of the PGA clause election by the Commission.

There are five pipeline companies which file annual PGA rate adjustments.[6] Currently they are permitted to file annually and to reflect those supplier rate changes for the forthcoming year that are already known. This procedure was permitted in order to facilitate the recovery of purchased gas costs by the distribution customers. The companies will not be required to file semiannual PGA rate changes but will be allowed to continue annual adjustments, as provided in their present tariffs, provided that they make no more than two PGA filings a year. These companies will be allowed carrying charges consistent with the regulation.

For the smooth and effective execution of this order, it is necessary that supplier pipelines provide information concerning their proposed adjustments to their purchasers who must make concurrent PGA filings. Such information should be provided at least 15 days prior to the filing date of the purchasing pipeline. The Commission intends to monitor the practices of pipelines in this regard, and, if it finds the information is not provided in a timely manner, the Commission will initiate a rulemaking procedure prescribing the necessary procedures for providing the information.

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[6] Colorado Interstate, Kansas-Nebraska, Northern Natural Gas, Inter City, and Northern Natural (Peoples Division).

To avoid possible complications for the affected pipelines, this rulemaking will become effective on January 1, 1979. Therefore, pipelines must file tariff sheets conforming their existing PGA clauses to these regulations on or before December 1, 1978, to become effective no earlier than and no later than January 1, 1979. After January 1, 1979, pipelines will not be permitted to reflect changes in purchased gas costs through PGA clauses unless they have PGA clauses in effect which conform to the provisions of the amendments promulgated in this order. Finally, pipelines shall also revise the effective dates for other approved rate adjustment provisions to comply with the PGA effective dates prescribed by this order.

MISCELLANEOUS COMMENT

A few comments expressed concern about coordination between the Commission adjustment procedures and various states' adjustment procedures. The State of Kansas and the Public Service Co. of Colorado requested that the Commission refrain from granting retroactive approvals. In Kansas, it is alleged, a retroactive approval can cause distribution companies employing cycle billing to absorb the wholesale rate changes, sometimes only temporarily, since the State Corporation Commission requires FERC approval before a wholesale rate increase may be passed on to consumers. The Public Utility Co. of Colorado does not allow rate changes to become effective retroactively. Thus, it is stated, where a retroactive rate increase is approved by the FERC, the distribution company is forced to absorb it. Indiana Gas Co., Inc. (Indiana Gas) requested the Commission to adopt the policy of suspending PGA filings whenever action cannot be taken within 30 days. When more than 30 days lapses, Indiana Gas states that it is forced by State requirements to absorb the costs that arise between the effective date of the filing and the date of FERC approval.

This Commission shares the concern of these parties that adequate notice be given to distributors who must pass on FERC—approved purchased gas costs. In view of this, the Commission shall grant waiver of the 30 day notice requirement for all section 4 rate filings, including PGA filings, only where the pipeline has carried the burden of demonstrating good cause for such waiver.

The following suggestions were also made by various commentators:

(1) Offset the amounts in the carrying charges with the amounts which are subject to refund.

(2) Suspend the semiannual PGA filings due date when an adjustment falls within a test period contained in a pipeline's general rate increase.

(3) Exclude additional companies from the effect of the rulemaking.

In regard to No. 1 above, the suggestion assumes on its face that pipeline companies are not entitled to any funds collected subject to refund. This is an incorrect assumption and the Commission declines to adopt this suggestion. In regard to No. 2 above, the cost of purchased gas constitutes the largest single component of a pipeline company's cost of service and any deferral of a justified filing would unduly penalize the company and create administrative burdens upon its customers. For this reason, the Commission declines to adopt this suggestion. In regard to No. 3 above, the notice of proposed rulemaking recognized that certain pipeline companies already had effective PGA clauses that were consistent with the purpose of the proposal and suggested that such clauses should not be affected by this rulemaking. Finally, the Commission shall not adopt the suggestion to exclude more companies from the effect of this rulemaking.

SUMMARY OF THE AMENDMENTS

Section 154.38(d)(4)(iv)(*a*) requires purchased gas adjustments to be filed semiannually and on the dates specified in this order.

Section 154.38(d)(4)(iv)(*b*) allows carrying charges on all balances in Account 191, provided the company adopts the principles of interperiod income tax allocation in connection with the balances recorded in the unrecovered purchased gas cost account. Carrying charges shall be equal to the current rate of interest on pipeline refunds established by the Commission.

Section 154.38(d)(4)(viii) requires the pipelines to file tariff sheets to conform their existing PGA clauses on or before December 1, 1978. These tariff sheets will become effective no earlier than nor no later than January 1, 1979. After

January 1, 1979, changes in purchased gas costs cannot be tracked under PGA clauses unless the effective PGA clause conforms with these amendments. (Natural Gas Act (15 U. S. C. 717c, g, i and o). Administrative Procedure Act (5 U. S. C. 553), Department of Energy Organization Act, (42 U. S. C. 7101, et seq.), and E. O. 12009, 42 FR 46267.)

In consideration of the foregoing, part 154, chapter I of Title 18, the Code of Federal Regulations is amended as set forth below, to become effective January 1, 1979.

By the Commission.

KENNETH F. PLUMB,
Secretary

[¶ 30,021]

43 F. R. 52219 (November 9, 1978)

SUBCHAPTER A—GENERAL RULES

PART 1—RULES OF PRACTICE AND PROCEDURE

Procedures for Review of Remedial Orders Issued by the Secretary of Energy

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final regulations.

SUMMARY: The Federal Energy Regulatory Commission is amending its Rules of Practice and Procedure to provide procedures for Commission review of remedial orders issued by the Secretary of Energy. The final regulations implement the Commission's authority under section 503(c) of the Department of Energy Organization Act.

EFFECTIVE DATE: December 11, 1978.

FOR FURTHER INFORMATION CONTACT:

Alexander M. Peters, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, 202-275-4227.

Bonnie Cord, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, 202-275-4210.

A. BACKGROUND

On May 2, 1978, the Federal Energy Regulatory Commission (Commission) issued a notice of proposed rulemaking (43 FR 19669, May 8, 1978) to establish procedures, pursuant to section 503 of the Department of Energy Organization Act, Pub. L. 95-91 (Act), for review by the Commission of remedial orders issued by the Secretary of Energy (Secretary). A public hearing was held on May 25, 1978, at which six persons testified, five representing large oil companies and the American Petroleum Institute, and one representing an association of small companies. Thirty-two written comments were received. While those testifying at the hearing predominantly represented large integrated oil companies, the written comments were received from a wide spectrum of persons affected by the regulations, including large integrated oil companies, trade associations, independent producers, refiners, resellers, retailers, distributors, municipalities owning electric systems, the consumer division of a State attorney general's office and an energy consulting firm. Many of the suggestions made in the testimony and in the comments have been incorporated into the final rule.

B. SUMMARY OF THE COMMISSION'S FINAL REGULATIONS

This rulemaking establishes procedures necessary to implement the Commission's responsibility under section 503 of the Act. Section 503(a) gives the Secretary authority to issue a remedial order to any person, firm, or association whom he believes, after investigation, has violated any regulation, rule, or order issued pursuant to the Emergency Petroleum Allocation Act of 1973 (Pub. L. 93-159), as amended (EPAA). Section 503(b) of the Act provides that the remedial order will become effective 30 days after receipt by the person to whom it is issued unless the person notifies the Secretary that he intends to contest the order. Section 503(c) provides that the Secretary, if notified that a remedial order will be contested, must immediately notify the Commission, and the Commission is required to stay the effect of the remedial order unless it finds that the public interest requires immediate compliance. Section 503(c) further states:

> The Commission shall, upon request, afford an opportunity for a hearing, including, at a minimum, the submission of briefs, oral or documentary evidence, and oral arguments. To the extent that the Commission in its discretion determines that such is required for a full and true disclosure of the facts, the Commission shall afford the right of cross examination. The Commission shall thereafter issue an order, based on findings of fact, affirming, modifying or vacating the Secretary's remedial order, or directing other appropriate relief, and such order shall, for the purpose of judicial review, constitute a final agency action * * *.

This rulemaking extablishes a new § 1.38 in part 1 of title 18, Code of Federal Regulations, consisting of procedures to implement the Commission's responsibility under section 503 of the Act.

Scope. As provided in paragraph (a), § 1.38 is applicable to the review of the contested orders issued by the Secretary pursuant to section 503(a) of the Act and initiated by notices of probable violation, proposed remedial orders or other formal administrative initiating documents issued on or after October 1, 1977. Several comments have suggested that the scope be enlarged to include review of orders initiated by formal administrative documents prior to October 1, 1977. However, in light of section 503(f), the Commission declines to take jurisdiction over matters initiated prior to October 1, 1977. Section 1.38 is thus limited to review of contested remedial orders which were initiated by a formal administrative document on or after October 1, 1977.

Request for nondisclosure. Section 1.38(c) of the final rules describes the procedures by which a party may request that information, which is submitted in a proceeding conducted under this section, be withheld from public disclosure. The party must: (1) Request the presiding officer not to disclose the information; (2) submit a second copy of the document from which the information which is claimed to be exempt from disclosure has been deleted; (3) indicate in the original document that it contains information which is exempt from disclosure; and (4) submit a statement that would justify the withholding of the information under an exception in the Freedom of Information Act (5 U.S.C. 522), under 18 U.S.C. 1905, or under other law. Information thus submitted will be treated as being exempt from public disclosure. Subject to the requirements of the Freedom of Information Act, the information will not be disclosed except to participants in the proceeding, upon request, under the restriction that they may not use or disclose the information except in the context of the proceeding conducted under this section and that they must return all copies of the information, at the conclusion of the proceeding, to the person who submitted the information.

The final rule differs from the proposed rule in two respects. First, the final rule provides that information which is claimed to be exempt from public disclosure requirements is automatically treated as exempt, whereas in the proposed rule the presiding officer was required to make a determination as to its exempt status. The final rule thus eliminates the delay to the proceeding caused by the requirement to make determinations on all information claimed to be confidential, while still providing protection for information which is confidential.

The final rule also differs from the proposed rule in that, in the final rule, information claimed to be exempt from disclosure is automatically disclosed on the aforementioned conditions to other participants in the proceeding, if they request the information and if they agree to the restrictions on its use. Under the proposed rule, the presiding officer was required to make a second determination as to whether the information could be disclosed to other participants. The purpose of the second determination in the proposed rule was to reduce the possibility that a party may be required to risk disclosing trade secrets or sensitive financial data to competitors in order to defend itself in an action before the Commission. However, the proposed rule allowed for the possibility that the presiding officer's decision in the proceeding might be based upon information to which other participants had no access or which they had no opportunity to contest. In order to balance these conflicting interests, the Commission specifically sought comments on the issue in its notice of proposed rulemaking. The comments and testimony suggested that the information should be released to other participants under a protective order, limiting use of the information to the proceeding conducted pursuant to this section and requiring return of the information at the conclusion of the proceeding. The Commission has adopted this suggestion in the final rule.

Commencement of proceedings. Section 1.38(d) provides that a proceeding under this section is commenced by written notice to the Commission by the Secretary or his delegate that he has been notified by the recipient of an order (the petitioner) that the order will be contested. At the same time the Secretary is required to serve the contested order on participants in the prior proceedings and on persons denied participation in the prior proceedings. The contested order may be a remedial order under 10 CFR 205.199B, an interim remedial order for immediate compliance under 10 CFR 205.199D, or an order of disallowance under 10 CFR 205.199E. The proceeding is also commenced by the petitioner's filing a notice of petition for review of an interim remedial order for immediate compliance under 10 CFR 205.199D. Upon notice from the Secretary in the case of an interim or remedial order for immediate compliance, from the petitioner, a presiding officer shall be designated, by the Commission or its designee, for the proceeding. In the notice of proposed rulemaking, the Commission requested comments as to the desirable qualifications and experience of the presiding officer to be appointed in view of the Commission's resources. While some comments responded that only an administrative law judge would be qualified to preside, the majority of comments indicated that the nature of the particular case would determine the necessary qualifications of the presiding officer; that is, where a particular proceeding involved an extensive or complex evidentiary hearing, an administrative law judge should preside, whereas in other cases a staff lawyer knowledgeable in administrative law would suffice. Accordingly, the Commission has decided to retain the flexibility to determine whom it will appoint as presiding officer.

Stay of contested order. Section 1.38(e), which is essentially unchanged from its proposed form, provides that upon filing of the notice by the Secretary under paragraph (d)(1) or the petitioner under paragraph (d)(2) the contested order is automatically stayed unless the presiding officer finds, upon request of the Secretary or other participants, that the public interest requires immediate compliance with the contested order. A request not granted within 10 days would be denied. The presiding officer could extend the time for a determination for up to 7 days. The presiding officer will notify participants of the determination, which may be appealed to the Commission under § 1.28.

Pleadings. Section 1.38(f)(1) of the final rule provides that, within 20 days after filing of notice by the Secretary under paragraph (d), the Secretary must file with the Secretary of the Commission, for the presiding officer, a copy of the contested order, which should contain a complete statement of the factual and legal basis of the order, and must certify to the Secretary of the Commission, for the presiding officer, two copies of the entire record developed in the proceedings before the Secretary. One copy of the record must be complete. The second copy shall have had deletions made of information which the Secretary has determined is confidential or otherwise exempt from public disclosure. The first copy will be made available to participants under the conditions set forth in paragraph (c) (6) and (7). In addition, the Secretary may file a statement, similar to a complaint, setting forth the elements of the alleged offense.

Paragraph (f)(2) provides that the petitioner, within 15 days after the Secretary files the contested order and the record, must file, and serve on all parties, an answer admitting or denying each of the Secretary's findings in the contested order and setting forth affirmative defenses, if any. In the answer, the petitioner may also contest any portion of the record of proceedings before the Secretary which the Secretary certified to the presiding officer and may request permission to raise new facts and issues and to conduct discovery under the criteria set forth in paragraphs (g) and (h), respectively. The reason for allowing the Secretary 20 days to file his statement and allowing the petitioner only 15 days to file the answer is that it has been estimated that 20 days are necessary for the Secretary to compile the record which he must certify to the presiding officer. In contrast, 15 days appears to be sufficient for the petitioner to submit an answer, which need only be a simple statement of his case.

Paragraph (f)(1)(ii) provides that if the petitioner, in the answer, has requested permission to raise new facts or issues, the Secretary may, within 10 days after the filing of the petitioner's answer, file a reply responding to the petitioner's request and requesting permission to raise new facts and issues which: (1) Are necessary to support the Secretary's case as a result of the new facts and issues raised by the petitioner; and (2) are necessary for a full and true disclosure of the facts. In his reply, the Secretary may also request permission to conduct discovery relating to the new facts and issues he wishes to raise.

Paragraph (f)(3) provides that a person may request permission to intervene in the proceedings conducted under this section if the person claims: (1) That he or she has an interest which may be directly affected and which is not adequately represented by existing parties, and that he or she may be bound by Commission action in the proceeding; or (2) that he or she has any other interest so that participation by the person may be in the public interest. A person who wishes to intervene must file with the Secretary of the Commission, for the presiding officer, a request to intervene within 20 days after the commencement of the proceedings under paragraph (d). The presiding officer may, in extraordinary circumstances and for good cause shown, authorize a late filing. The request to intervene must thoroughly advise the presiding officer and participants in the proceeding as to the nature of the filing party's interest and grounds for intervention as well as the facts or law to be raised, citing authorities relied on.

The request to intervene may also request permission to raise new facts and issues and to conduct discovery in accordance with paragraphs (g) and (h), respectively. Participants in the proceedings may file answers to the request for intervention within 15 days after the filing of the request. If a participant does not file an answer, he shall be deemed to waive any objection to the granting of the request. The presiding officer may grant or deny requests to intervene, in whole or in part, or may authorize limited participation where appropriate. The determination of the presiding officer shall be served on all participants. A person whose request for intervention is denied by the presiding officer may submit comments under paragraph (m)(3) requesting the Commission to allow the intervention.

Subparagraphs (1)(iii) and (2)(iii) of paragraph (f), respectively, require the Secretary and the petitioner each to file, and serve on other participants, a brief which fully states the respective case, supported by references to all authorities relied on. The time within which the Secretary must file his brief depends on the nature of the particular proceeding. If none of the participants, including persons requesting intervention, have requested permission to raise new facts or issues or to conduct discovery, the brief is due within 20 days after the filing of the petitioner's answer. If the presiding officer determines that no discovery will be permitted, the Secretary must file his brief within 20 days after the presiding officer so determines. If discovery is permitted, the Secretary must file his brief within 20 days after the conclusion of the time period set for discovery. The petitioner's brief must be filed within 15 days after the filing of the Secretary's brief.

The comments received suggested changes to the proposed pleading procedures, many of which have been adopted in the final regulations. Objection was made to the requirement in the proposed rules that the Secretary and the petitioner were required to file briefs before discovery had been conducted. Accordingly, paragraph (f) of the final regulations requires the Secretary to submit his statement of the case (either by relying on the contested order or by submitting a separate statement) and the petitioner to file only a simply answer prior to discovery. Full briefs are to be submitted after discovery.

A few comments objected to the Secretary being permitted to file a reply under proposed § 1.38(f)(1)(ii) to the petitioner's answer on the grounds that such additional pleadings gave the Secretary an advantage. In the final regulations, the Secretary is permitted under § 1.38(f)(1)(ii) to file a reply to the petitioner's answer only if the petitioner has requested permission to raise new facts or issues and only to the extent that the Secretary may respond to the petitioner's request and may request permission to raise new facts and issues, and to conduct discovery, necessary to support his case in light of the petitioner's new facts and issues.

Several comments objected to § 1.38(f)(3) and (4) of the proposed regulations, which permitted intervention by all persons who had participated in the prior proceedings and by persons denied the opportunity to participate in the prior proceeding upon a showing that the denial was wrongful. Some of the comments argued for no intervention or very limited intervention on the basis that the Secretary adequately represents the public interest, while others, notably consumers of petroleum products, argued that liberal intervention should be permitted especially as to those persons who would receive the economic benefits of the remedial orders. Almost all of the comments responding to this issue agreed that the Commission should set its own standards for intervention rather than rely on the Secretary's determination as to who could intervene in the prior proceedings. The Commission agrees that it should set its own standards for intervention and has done so.

A large number of the comments objected to the requirement that the Secretary certify the record of the prior proceedings to the presiding officer under paragraph (f)(1)(i) and to the requirement that the petitioner contest the portions of the record in dispute, expressed in the final rules in paragraph (f)(2)(ii). The comments argued that these requirements favor the Secretary, shifting the burden to the petitioner to disprove the Secretary's record. They suggest that the Commission must conduct a *de novo* proceeding in every case in order to establish an independent record. The Commission has rejected this suggestion based in part upon the conclusion that a *de novo* proceeding is neither required nor desirable in every case, as discussed below, and in part upon the belief that the Commission's procedures effectively require the Secretary to sustain the burden of proof. The Commission's procedures are designed to obtain a record which satisfies due process standards from which a determination may be made as to whether the remedial order should issue. This record may be established in part by the Secretary's record and in part by the proceeding conducted before the presiding officer. Those portions of the Secretary's record which are contested by the petitioner or other participants, and those portions found to be inadequate by the presiding officer, may be opened for further proceedings before the Commission. Furthermore, new facts and issues may be raised in accordance with paragraph (g). In all cases, the presiding officer will conduct an independent scrutiny of all parts of the record, including the uncontested portions, in order to arrive at a decision. The record as supplemented and the review thereof should provide a sound basis for a determination of whether the Secretary has sustained the burden of demonstrating that the remedial order should issue.

New Facts and Issues. Section 1.38(g) sets forth the conditions under which the various participants may request permission to raise new facts or issues not raised in prior proceedings on the contested order. The petitioner may raise new facts of issues if they are necessary for a full and true disclosure of the facts and if the new facts or issues: (1) were not known and could not, with the exercise of due care, have been known at the time they would otherwise have been raised in prior proceedings; (2) are facts or issues that the petitioner was unable to raise in the prior proceedings because of unduly restrictive time limits imposed by the Secretary; or (3) are facts or issues that the petitioner was not permitted to raise in the prior proceedings due to erroneous adverse procedural rulings. The Secretary may request permission to raise new facts or issues not raised in the prior proceedings, which shall be granted if they are necessary for a full and true disclosure of the facts and if they are necessary to support the Secretary's case as a result of new facts and issues raised by the petitioner. Intervenors who did not participate in the prior proceedings may raise new facts or issues subject to the same criteria applicable to the petitioner. Intervenors who participated in the prior proceedings may raise new facts or issues if they are necessary for a full and true disclosure of the facts and if the new facts or issues: (1) were not known, and could not, with the exercise of due care, have been known to the intervenor at the time they would otherwise have been raised during the prior proceedings; (2) are facts or issues that the intervenor was not able to raise at the time they could have been raised during the prior proceeding because of unduly restrictive time limits imposed by the Secretary; or (3) are facts or issues that the intervenor was not permitted to raise in the prior proceedings due to erroneous adverse procedural rulings. The presiding officer shall determine whether to grant or deny, in whole or in part, the request to raise new facts or issues.

Comments suggested that the Commission allow new facts or issues to be raised which are necessary for a full and true disclosure of the facts without regard to whether they were, or could have been, raised below. The Commission has rejected this suggestion, believing that, in the interest of administrative efficiency, the parties should be required to present their case fully before the Secretary and that the Commission's proceedings should be directed toward correcting inequities in the prior proceedings.

Discovery. Section 1.38(h) permits the petitioner and intervenors who participated in the prior proceedings to request permission to conduct discovery which is necessary for a full and true disclosure of the facts and which: (1) relates to new facts or issues permitted to be raised under paragraph (g); or (2) was not permitted to be conducted by the petitioner or the intervenors, respectively, in prior proceedings due to erroneous adverse rulings. The Secretary and intervenors who did not particiapte in the prior proceedings may request discovery related to new facts and issues which the Secretary or an intervenor, respectively, has raised in accordance with paragraph (g). The presiding officer shall determine whether to grant or deny, in whole or in part, the requests for discovery and shall set a time limit within which such discovery must be completed.

Section 1.38(h) adds written interrogatories to the devices by which discovery may be conducted.

Hearing. Section 1.38(i) provides that any participant may request a hearing, which request shall be granted, or the presiding officer may convene a hearing on his own motion. The hearing shall include an opportunity for the submission of oral or documentary evidence and oral arguments. Any participant may request an opportunity for cross-examination, which request must include the reasons why the cross-examination is necessary for full and true disclosure of the facts. The presiding officer may also provide the opportunity for cross-examination on his own motion if he or she determines that it is necessary for a full and true disclosure of the facts. Comments suggested that more specific guidance be given in the regulations to direct the presiding officer as to when cross-examination is necessary for a full and true disclosure of the facts, such as a provision stating that opportunity for cross-examination shall be granted as a matter of right on any material fact in dispute. The Commission believes that the statutory standard is sufficient guidance, and that since a presiding officer's denial of a request for cross-examination may be the subject of written comments to the Commission under paragraph (m)(3), due process is not denied.

The presiding officer may convene a prehearing conference and may determine the issues to be resolved in the proceeding and the time available for oral argument.

Conduct of the hearing. Section 1.38(j) states that the presiding officer shall be responsible for the conduct of the hearing including the order of proceaure.

Burden of proof. Section 1.38(k) provides that the Secretary shall have the burden of going forward and must sustain the burden of proof with respect to all elements of his case, by a preponderance of the evidence.

Proposed findings of fact, conclusions of law and comments. Section 1.38(l) provides that any participant may, within 10 days after the conclusion of the hearing, or if no hearing is held, within 20 days after the filing of the petitioner's brief under (f)(2)(iii), file proposed findings of fact and conclusions of law, comments in support thereof and any objections to procedural rulings of the presiding officer. Any participant may file a reply to proposed findings of fact and conclusions of law within 10 days after the filing thereof.

Proposed order. Section 1.38(m) provides that the presiding officer shall issue a decision and proposed order, based on findings of fact, affirming, modifying or vacating the contested order or directing other appropriate relief. The proposed order shall be based upon the entire record before the presiding officer, including the record certified by the Secretary. The presiding officer shall certify a copy of the record in the hearing including the proposed order, to the Commission. The proposed order shall be served on all participants. Participants may, within 15 days of the issuance of the proposed order, file with the Commission written comments on the proposed order or on any procedural or substantive rulings of the presiding officer.

Commission action. Section 1.38(n) provides that, upon consideration of the entire record and the proposed order, the Commission shall issue a final order affirming, modifying, or vacating the contested order or directing other appropriate relief. The final order constitutes final agency action for purposes of judical review. The Commission may, instead of issuing a final order, remand the proceeding to the presiding officer or take other appropriate action.

Ex parte communications. Section 1.38(o) states that the ex parte provisions of § 1.4(d) of Part 1 apply to proceedings under this section as if such proceedings were contested on-the-record proceedings pending before the Commission. The ex parte provisions shall apply commencing with the Secretary's issuance of a proposed remedial order under 10 CFR 205.192, an interim remedial order for immediate compliance under 10 CFR 205.199D, or a proposed order of disallowance under 10 CFR 205.199E.

Withdrawal of petition for review. Section 1.38(p) provides that the petitioner may at any time submit to the presiding officer and serve on other participants, a request to withdraw the petition for review of the contested order. The presiding officer shall then issue, and serve on all participants in the proceeding, an order terminating the proceeding conducted pursuant to this section. The order shall become effective 10 days after issuance. Termination of the proceeding may be appealed to the Commission, within 10 days after issuance, except that if the Commission has not acted on an appeal within 30 days, it shall be deemed denied. The termination order shall be stayed pending the appeal. If the termination order is rescinded by the Commission, the proceeding shall continue in accordance with this section. The Commission believes that any intervenor who claims to be damaged by the petitioner's withdrawal of the petition for review can obtain judicial review thereof and, accordingly, its interest is protected.

Sanctions. Paragraph (g) sets forth certain civil and criminal sanctions the Commission may seek to impose on any person who is violating, or is about to violate, any rule, regulation, restriction, condition, or order the Commission made or imposed under this section.

The nature of the Commission's review. The Commission believes, based upon an examination of the statute and the legislative history, that section 503 of the Act does not require the Commission to conduct a de novo proceeding in every case of remedial order review. The statute requires only a hearing consisting of the submission of briefs, oral and documentary evidence and oral argument. The fact that an opportunity for cross-examination is to be granted only if, in the discretion of the Commission, it is necessary for a full and true disclosure of the facts, indicates that a full de novo hearing is not required. Further, the authority of the Secretary under section 503(d) to set reasonable time limits for the Commission to complete its review indicates that a de novo proceeding is not intended as a matter of course.

In the legislative history, the statement of managers accompanying the conference report explained that the purpose of the Commission's review was to guarantee a separation of the prosecutorial and judicial functions by assuring a departmental review of remedial orders by officials who had no part in the issuance of the order. S. Rep. No. 95-367, 95th Congress, 1st sess. 85 (1977). The managers further emphasized that section 503 was intended to reaffirm Congress intent that "notions of fair play and due process be followed in administrative proceedings." Id. at 85–86. Neither of these concerns, separation of prosecutonial and judicial functions and the extensioh of due process, requires a de novo hearing in every case. A separation of the judicial and prosecutonial functions is accomplished by Commission review supplemented by limited evidentiary proceedings where necessary. Second, the extension of due process is satisfied in many cases by an independent scrutiny of the record and by less than a de novo proceeding, so long as each side has been afforded an opportunity to present its case in full.

During the debate in the Senate on the amendment adding section 503 to the bill, there was concern about possible delay of a final decision that might be caused by the amendment, frustrating congressional intent to speed up the administrative process. Senator Javits, who introduced the amendment, indicated that delays could be minimized by providing the Commission the discretion to deny opportunity for cross-examination where appropriate and by the fact that the Secretary could impose a reasonable time limit for Commission review, process.

Senator Javits, who introduced the amendment, indicated that delays could be minimized by providing the Commission the discretion to deny op-

portunity for cross-examination where appropriate and by the fact that the Secretary could impose a reasonable time limit for Commission review, which he estimated to be 3 or 4 months. 123 Cong. Rec. S7935-36 (daily ed. May 18, 1977). If the proceedings were entirely de novo, the process would take much longer.

The House debate confirms the proposition that a de novo proceeding was not contemplated. Note the statement of Representative Eckhardt, who introduced the amendment regarding section 503, stating that section 503 provides "an oral hearing, gives [the petitioner] an opportunity to contest the agency position and gives him a record on which a court may ultimately determine whether the agency decision was based substantially on the record as a whole." 123 Cong. Rec. H5372 (daily ed. June 3, 1977). These procedures are provided under the Commission's rule.

Concern in the House centered around the inability of small companies to obtain review of remedial orders due to a lack of financial resources. Representative Brown of Ohio stated:

> It seems to me that it is very important to have a sound, prudent, regular administrative procedure. [This] amendment ideally does that. One of the things we have been observing over the past few months is that small independent producers who are challenged by the FEA just simply have to abandon their cases and accept the FEA ruling because they do not have the wherewithal to fight the FEA's decision. This will help assure that they will have the same kind of rights that bigger outfits with stronger resources have in trying to respond to the bureaucracy.
>
> *Mr. Eckhardt:* The gentleman has stated the situation accurately.

Id. A proceeding that unnecessarily duplicates that part of a record established in prior proceedings, which is not contested, unnecessarily delays a resolution of the case and increases the financial burden on a person seeking relief.

Accordingly, in view of the congressional intent that due process considerations be meshed with minimization of the time required for review and minimization of financial burdens imposed by Commission review, the Commission concludes that de novo proceedings are not required for Commission review of remedial orders under section 503 of the act.

(Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267, Natural Gas Act, 15 U.S.C. § 717 et seq., Federal Power Act, 16 U.S.C. 792 et seq.)

In consideration of the foregoing, Part 1, Subchapter A of Chapter I, Code of Federal Regulations, is amended as set forth below, effective December 11, 1978.

By the Commission.

KENNETH F. PLUMB,
Secretary.

1. Part 1, Subchapter A, Chapter I of Title 18, Code of Federal Regulations, is amended in the table of contents by adding in the appropriate numerical order a new section number and heading to read as follows:

PART I—RULES OF PRACTICE AND PROCEDURES

* * * * *

§ 1.38 Commission Review of Remedial Orders.

* * * * *

2. Part 1, Subchapter A, Chapter I of Title 18, Code of Federal Regulations, is amended in the Statement of Authority by inserting between "under" and "unless otherwise noted," a phrase to read as follows:

AUTHORITY:

* * * * *

15 U.S.C. 717 et seq., 16 U.S.C. 792 et seq., 42 U.S.C. 7101 et seq., E.O. 12009, 42 FR 46467,

* * * * *

3. Part 1, Subchapter A, Chapter I of Title 18, Code of Federal Regulations, is amended by adding a new § 1.38 to read as follows:

§ 1.38 Commission review of remedial orders.

(a) *Scope.* (1) The provisions of this section shall apply to proceedings of the Commission held in accordance with section 503(c) of the Department of Energy Organization Act, Pub. L. 95-91, 42 U.S.C. 7913(c), to review orders issued by the Secretary of Energy pursuant to section 503(a) of the Department of Energy Organization Act and initiated by notices of probable violation, proposed remedial orders, or other formal administrative initiating documents issued on or after October 1, 1977, which are contested by the recipient.

(2) Except as otherwise specifically provided in this section, the following provisions of the Part shall apply to proceedings under this section:

(i) § 1.1—The Commission;

(ii) § 1.2—The Secretary;

(iii) § 1.3—Notice of public sessions and proceedings;

(iv) § 1.4—Appearances and practice before the Commission;

(v) § 1.11—Amendments and withdrawal of pleadings;

(vi) § 1.12—Motions;

(vii) § 1.13—Time, extensions of time, issuance of orders;

(viii) § 1.14—Filings; docket; hearing calendar;

(ix) § 1.15—Formal requirements as to pleadings, documents and other papers filed in proceedings;

(x) § 1.16—Subscription and verification;

(xi) § 1.17—Service;

(xii) § 1.18 (b) and (d)—Conferences;

(xiii) § 1.21—Copies of transcripts;

(xiv) § 1.22—Witnesses;

(xv) § 1.23—Subpoenas;

(xvi) § 1.24—Depositions;

(xvii) § 1.25—Stipulations;

(xviii) § 1.26—Evidence;

(xix) § 1.27—Presiding officers;

(xx) § 1.36—Public information and requests; and

(xxi) § 1.51—Certificate of service.

(b) *Definitions.* For purposes of this section: "Commission" means the Federal Energy Regulatory Commission;

"contested order" means the remedial order, interim remedial order for immediate compliance, or order of disallowance being contested in proceeding pursuant to this section;

"interim remedial order for immediate compliance" means an interim remedial order for immediate compliance issued pursuant to 10 CFR 205.199D;

"order of disallowance" means an order of disallowance issued pursuant to 10 CFR 205.199E;

"participant" means, as appropriate, the Secretary, the petitioner, and intervenors;

"person" means any individual, association, company, corporation, partnership, or other entity however organized;

"petitioner" means a person who has received a remedial order, interim remedial order for immediate compliance, or order of disallowance who notifies the Secretary that he intends to contest the order;

"remedial order" means a remedial order issued pursuant to 10 CFR 205.199B;

"Secretary" means the Secretary of Energy or his delegate.

(c) *Request for nondisclosure of information.* (1) For purposes of this paragraph, nondisclosure means nondisclosure except as to the participants in the proceeding under conditions provided in subparagraphs (4) and (5).

(2) If any person filing under this section claims that some or all of the information contained in a document is exempt from the mandatory public disclosure requirements of the Freedom of Information Act (5 U.S.C. 552), is information referred to in 18 U.S.C. 1905, or is otherwise exempt by law from public disclosure, the person:

(i) shall request the presiding officer not to disclose such information, except to the participants in the proceeding under the conditions provided in subparagrahs (4) and (5), which request the person shall serve upon all participants in the proceeding;

(ii) Shall file, together with the document, a second copy of the document from which has been deleted the information for which the person requests nondisclosure and shall indicate in the original document that the original document is exempt, or contains information which is exempt, from disclosure;

(iii) Shall include a statement specifying why the information is privileged or confidential, if the information for which nondisclosure is requested is claimed to come within the exception in 5 U.S.C. 552(b)(4) for trade secrets and commercial or financial information;

(iv) Shall include a statement specifying the justification for nondisclosure, if the information for which nondisclosure is requested is not within the exception in 5 U.S.C. 552(b)(4).

(3) If the person filing a document does not submit a second copy of the document from which the appropriate information has been deleted, the presiding officer may assume that there is no objection to public disclosure of the document in its entirety.

(4) If information is submitted in accordance with subparagraph (2) of this paragraph, the information will not be disclosed except (i) as provided in the Freedom of Information Act, in accordance with § 1.36 of this Part, and (ii) upon request in accordance with subparagraph (5), to participants in the proceeding under the restrictions that the participants may not use or disclose the information except in the context of the proceeding conducted pursuant to this section and that the participants must return all copies of the information at the conclusion of the proceeding to the person who submitted the information under subparagraph (2).

(5) At any time, any participant may request the presiding officer to direct a person submitting information under subparagraph (2) to provide that information to the participant requesting the information under this subparagraph. The presiding officer shall so direct if the participant requesting the information agrees (i) not to use or disclose the information except in the context of the proceeding conducted pursuant to this section, and (ii) to return all copies of the information, at the conclusion of the proceeding, to the person submitting the information under subparagraph (2).

(6) If the information contained in the record of prior proceedings submitted by the Secretary under paragraph (f)(1)(i)(A), has been determined by the Secretary to be exempt from disclosure, the information shall not be disclosed except (i) as provided in the Freedom of Information Act, in accordance with § 1.38 of this Part, and (ii) upon request in accordance with subparagraph (7), to participants in the proceeding under the restrictions that the participants may not use or disclose the information except in the context of the proceeding conducted pursuant to this section and that the participants must return all copies of the information at the conclusion of the proceeding to the presiding officer.

(7) At any time, any participant may request the presiding officer to direct that the complete record of prior proceedings, including information determined by the Secretary to be exempt from disclosure, be made available to that participant. The presiding officer shall so direct if the participant requesting the complete record agrees (i) not to use or disclose the information determined to be exempt except in the context of the proceeding conducted pursuant to this section, and (ii) to return all copies of the information determined to be exempt to the presiding officer at the conclusion of the proceeding.

(d) *Commencement of proceeding.* (1) Except as provided in subparagraph (2), the proceeding pursuant to this section shall be commenced by the filing with the Secretary of the Commission, for the Commission, written notice by the Secretary that he has been notified by a petitioner that the petitioner intends to contest an order reviewable under this section. At the same time, the Secretary shall serve a copy of the contested order upon other participants in the prior proceedings and upon persons denied intervention in the prior proceedings and shall certify to the Commission that he has made such service, stating the names and addresses of persons served.

(2) The proceeding pursuant to this section with respect to an interim remedial order for immediate compliance shall be commenced by a petitioner's filing with the Secretary of the Commission, for the Commmission, and serving on other participants in the prior proceedings, if any a notice of petition for review of an interim remedial order for immediate compliance pursuant to 10 CFR 205.199D(h)(i)(1). The Commission shall defer consideration of the merits of the order until a final remedial order is issued by the Secretary.

(3) Upon receipt of notice from the Secretary under subparagraph (1), or upon receipt of a notice of a petition for review by the petitioner under subparagraph (2), the Commission or its designee shall designate a presiding of-

ficer for the proceeding, and the Commission or its designee shall notify participants in the prior proceedings and persons denied intervention in the prior proceedings of such designation.

(e) *Stay of contested order.* (1) Upon the filing of the notice with the Commission by the Secretary under paragraph (d)(1), or by the petitioner under paragraph (d)(2), the contested order shall be automatically stayed pending review pursuant to this section unless and until, upon request of the Secretary or other participant, the presiding officer finds that the public interest requires immediate compliance with the contested order.

(2) The Secretary or other participants may at any time, prior to the hearing under paragraph (l), or if there is no hearing, prior to the issuance of a proposed order under paragraph (m), file a petition requesting that the contested order not be stayed, or that the stay be lifted, and setting forth the legal and factual basis for the request.

(3) The presiding officer may request a written statement of the views of any participant regarding whether the contested order should be stayed or continue to be stayed and may convene an expedited hearing or conference on a petition under subparagraph (2).

(4) The presiding officer may grant the petition requesting immediate compliance where he finds that the public interest so requires and shall notify all participants of the determination.

(5) If the presiding officer has not granted the petition under subparagraph (2) within 10 days after it is filed, the petition shall be deemed denied. Prior to the expiration of the 10-day period the presiding officer may extend the period for decision up to 7 days. At the end of the extension, the petition, if not granted, shall be deemed denied.

(6) If the petition under subparagraph (2) is denied, the presiding officer shall notify the participants of such denial.

(7) A grant or denial of a petition under subparagraphs (2) and (3) may be appealed, within 10 days after the grant or denial, to the Commission in accordance with § 1.28. The contested order will remain stayed ending the Commission's disposition of the appeal.

(f) *Pleadings.* (1) *By the Secretary.*—(i) Within 20 days after the filing of notice by the Secretary under paragraph (d)(1), the Secretary:

(A) Shall file with the Secretary of the Commission for the presiding officer two certified copies of the entire record developed in prior proceedings on the contested order. One copy shall be complete and shall be deemed a part of the record upon which the order of the Commission is based, and shall be available to the participants subject to the conditions set forth in paragraph (c) (6) and (7); the second copy shall have had deletions made of information which the Secretary has determined to be confidential or not subject to disclosure;

(B) Shall file with the Secretary of the Commission for the presiding officer a copy of the contested order; and

(C) May, in addition, elect to file a statement setting forth the factual elements of the alleged violation, which statement the Secretary must serve on all participants in the proceeding.

(ii) If the petitioner requests permission to raise new facts or issues pursuant to paragraph (g)(1), the Secretary may file, within 10 days after the filing of the petitioner's answer, a reply responding to the petitioner's request to raise new facts or issues. In the reply, the Secretary may also request the permission of the presiding officer to raise new facts or issues under the criteria set forth in paragraph (g)(2) and to conduct discovery relating to the new facts or issues he may raise pursuant to paragraph (g)(2). Failure by the Secretary to request permission to raise new facts or issues or to conduct discovery in this reply shall constitute a waiver of the opportunity to do so at a later time in the proceeding.

(iii) The Secretary shall file with the Secretary of the Commission, for the presiding officer, and serve upon other participants in the proceedings, a brief in support of the affirmative case, which must set forth:

(A) The elements of the alleged violation, including references to all authorities upon which the Secretary relies, including but not limited to regulations, rulings, interpretations and decisions on appeals and exceptions issued by the Department or its predecessor agencies and precedents established by the Commission; and

(B) A complete statement of the factual and legal basis of the contested order.

(iv) The Secretary's brief shall be filed according to the following time period appropriate to the particular proceeding:

(A) If no participant (including persons requesting intervention) has requested permission to raise new facts or issues or to conduct discovery pursuant to paragraphs (f)(1)(ii), (f)(2)(ii), (f)(3)(vii), and (f)(3)(viii), within 20 days after the filing of the petitioner's answer under paragraph (f)(2)(i);

(B) If the presiding officer has determined, under paragraph (h)(4), that no discovery shall be permitted, within 20 days after the presiding officer's determination under paragraph (h)(4); or

(C) If discovery is permitted under paragraph (h)(4), within 20 days after the conclusion of the time period set for discovery under paragraph (h)(4).

(2) *By the petitioner.* (i) Within 15 days after the filing by the Secretary under subparagraph (1)(i), the petitioner shall file with the Secretary of the Commission, for the presiding officer, and serve upon the Secretary and other participants in the proceedings, an answer to the contested order admitting or denying each of the Secretary's findings in the contested order and setting forth affirmative defenses, if any.

(ii) In the answer, the petitioner may:

(A) Contest any part of the record which the Secretary certified to the presiding officer under subparagraph (1)(i)(A);

(B) Request permission to raise new facts or issues not raised in the prior proceedings if the new facts or issues meet the criteria set forth in paragraph (g)(1); and

(C) Request permission to conduct discovery, subject to the criteria provided in paragraph (h)(1). Failure by the petitioner to contest the record or to request permission to raise new facts or issues or to conduct discovery in this answer shall constitute a waiver of the opportunity to do so at a later time in the proceeding.

(iii) Within 15 days after filing of the Secretary's brief under paragraph (f)(1)(iii), the petitioner shall file with the Secretary of the Commission, for the presiding officer, and serve upon other participants in the proceeding, a brief stating fully the objections to the contested order, including references to all authorities upon which the petitioner relies, including but not limited to regulations, rulings, interpretations, and decisions on appeals and exceptions issued by the Department or its predecessor agencies and precedents established by the Commission.

(3) *By intervenors.* (i) A person qualifying under (ii) may request the presiding officer to permit intervention in the proceeding under this section in accordance with the procedures described in this subparagraph.

(ii) A request to intervene may be filed by any person claiming: (A) An interest which may be directly affected and which is not adequately protected by existing parties and as to which the person requesting intervention may be bound by the Commission's action in the proceeding; or (B) any other interest of such nature that participation by the person requesting intervention may be in the public interest.

(iii) A request to intervene shall set out clearly and concisely the facts from which the nature of the requester's alleged right or interest can be determined, the grounds of the proposed intervention, and the position of the intervenor in the proceeding, so as fully and completely to advise the participants and the presiding officer as to the specific issues of fact or law to be raised or controverted, by admitting, denying, or otherwise answering, specifically and in detail, each material allegation of fact or law raised or controverted, including references to all authorities upon which the requester relies, including, but not limited to, regulations, rulings, interpretations, and decisions on appeals and exceptions issued by the Department or its predecessor agencies and precedents established by the Commission.

(iv) Requests to intervene may be filed with the Secretary of the Commission, for the presiding officer, within 20 days after the Secretary's commencement of the proceeding under paragraph (d) unless, in extraordinary circumstance and for good cause shown, the presiding officer authorizes a late filing. A person requesting intervention shall serve the request to intervene on all participants in the proceeding at the same time the request is filed with the Secretary of the Commission.

(v) Any participant in the proceedings may file an answer to a request to intervene. Failure to object shall constitute a waiver of any objection to the granting of such request. If made, answers shall be filed within 15 days after the filing of the request to intervene.

(vi) After expiration of the time for filing answers to requests to intervene or default thereof, as provided in (v), the presiding officer will grant or deny such request, in whole or in part, or may, if found to be appropriate, authorize limited participation. The presiding officer shall serve the determination on a request to intervene upon all participants in the proceeding and upon the person requesting intervention. If the presiding officer denies a request for intervention, the person requesting intervention may submit comments to the Commission under paragraph (m)(3) requesting the Commission to permit the intervention under the standards set forth in paragraph (f)(3)(ii).

(vii) A person filing a request to intervene, may request therein the permission of the presiding officer to raise new facts or issues not raised in the prior proceedings on the contested order, if the new facts or issues meet the criteria set forth in paragraph (g)(3). Failure by the person requesting permission to intervene to request permission to raise new facts or issues in the request to intervene shall constitute a waiver of the opportunity to do so at a later time in the proceeding.

(viii) A person filing a request to intervene may request the permission of the presiding officer to conduct discovery, subject to the conditions set forth in paragraph (h)(3). Failure by the person requesting permission to intervene to request permission to conduct discovery in the request to intervene shall constitute a waiver of the opportunity to do so at a later time in the proceeding.

(g) *New facts and issues.* (1) *Raised by the petitioner.* In the answer, as provided in paragraph (f)(2)(ii)(B), the petitioner may request permission of the presiding officer to raise new facts or issues not raised in prior proceedings on the contested order that (i)(A) are facts or issues that were not known and could not, with the exercise of due care, have been known to the petitioner at the time they would otherwise have been raised during the prior proceedings; (B) are facts or issues that the petitioner was unable to raise at the time they could have been raised during the prior proceedings because of unduly restrictive time limits imposed by the Secretary; or (C) are facts or issues that the petitioner was not permitted to raise in the prior proceedings due to erroneous adverse procedural rulings; and (ii) are necessary for a full and true disclosure of the facts.

(2) *Raised by the Secretary.* In his reply under paragraph (f)(1)(ii), the Secretary may request permission of the presiding officer to raise new facts or issues not raised in prior proceedings on the contested order that (i) are necessary to support the Secretary's case as a result of new facts or issues raised by the petitioner under paragraph (f)(2)(ii)(B) and this paragraph; and (ii) are necessary for a full and true disclosure of the facts.

(3) *Raised by intervenors.* In the request to intervene under paragraph (f)(3)(iii) and this paragraph, an intervenor may request permission of the presiding officer to raise new facts or issues not raised in prior proceedings on the contested order that: (i) if the intervenor did not participate in the prior proceedings, meet the criteria of subparagraph (1) (i) and (ii); or (ii) if the intervenor participated in the prior proceedings, are (A)(I) facts or issues that were not known and could not, with the exercise of due care, have been known to the intervenor at the time they would otherwise have been raised during the prior proceedings; (II) facts or issues that the intervenor was unable to raise at the time they could have been raised during the prior proceedings because of unduly restrictive time limits imposed

by the Secretary; or (III) facts or issues that the intervenor was not permitted to raise in the prior proceedings due to erroneous adverse procedural rulings; and (B) are necessary for a full and true disclosure of the facts.

(4) *Determination by the presiding officer.* The presiding officer shall determine whether to grant or deny, in whole or in part, the requests of the participants to raise new facts or issues and shall serve those determinations on all participants in the proceeding.

(h) *Discovery.* (1) *By petitioner.* In the answer under paragraph (f)(2)(ii) the petitioner may request permission of the presiding officer to conduct discovery, where such discovery (i) relates to new facts or issues raised in accordance with paragraph (g)(1); or (ii)(A) was not permitted in the prior proceedings on the contested order due to erroneous adverse procedural rulings; and (B) is necessary for a full and true disclosure of the facts.

(2) *By the Secretary.* In the reply under paragraph (f)(1)(ii), the Secretary may request permission of the presiding officer to conduct discovery where such discovery relates to new facts or issues raised in accordance with paragraph (g)(2).

(3) *By intervenors.* In a request to intervene under paragraph (f)(3)(viii), an intervenor may request permission of the presiding officer to conduct discovery where such discovery: (i) relates to new facts or issues raised in accordance with paragraph (g)(3); or (ii) if the intervenor participated in the prior proceedings, (A) such discovery was not permitted in prior proceedings on the contested order due to erroneous adverse procedural rulings; and (B) such discovery is necessary for a full and true disclosure of the facts.

(4) *Determinations by the presiding officer.* The presiding officer shall determine whether to grant or deny, in whole or in part, the requests of the participants for discovery and shall set a time limit within which all discovery must be conducted.

(5) *Interrogatories.* In addition to discovery devices applicable to this section under paragraph (n)(2), participants may conduct discovery by means of written interrogatories under conditions determined by the presiding officer.

(i) *Hearing.* (1) Any participant may, within 10 days after filing of the petitioner's brief under paragraph (f)(2)(iii), file a request for a hearing or a motion for the opportunity for cross-examination including the reasons why cross-examination is necessary for a full and true disclosure of the facts.

(2) If a participant has filed a request for a hearing, the presiding officer shall grant the request for a hearing. The hearing shall include an opportunity for the submission of oral or documentary evidence and oral arguments.

(3) The presiding officer may at any time, on his own motion, convene a hearing.

(4) As soon as practicable after receiving a request for hearing under subparagraph (1) or after determination on his own motion that a hearing will be held under subparagraph (3), the presiding officer shall give notice to all participants of the time and place of the hearing.

(5) The presiding officer shall determine the issues to be resolved in the proceeding, may specify the time available for oral argument and shall give notice thereof to the participants. The presiding officer may require additional information from the participants and may convene a prehearing conference for the purpose of determining the issues or the nature of the proceeding to be held.

(6) If at any time prior to the issuance of a proposed order pursuant to paragraph (m), upon motion of any participant or on his own motion, the presiding officer in his discretion determines that it is necessary for a full and true disclosure of the facts, he may order that the participants be afforded the opportunity for cross-examination on any facts or issues raised in the proceeding.

(j) *Conduct of the hearing.* The presiding officer shall be responsible for conduct of the hearing, including the order of procedure.

(k) *Burden of proof.* (1) The Secretary shall have the burden of going forward and must sustain the burden of proof with respect to all disputed elements of his affirmative case.

(2) The proposed order under paragraph (m) shall be based upon a preponderance of the evidence.

(l) *Proposed findings of fact, conclusions of law and comments.* (1) Within 10 days after the conclusion of the hearing, or, if no hearing is held, within 20 days after the filing of the petitioner's brief under paragraph (f)(2)(iii), any participant may file with the Secretary of the Commission for the presiding officer, and serve upon the other participants, proposed findings of fact and conclusions of law, comments in support thereof and any objections with respect to procedural rulings of the presiding officer.

(2) Within 10 days after the filing of proposed findings of fact and conclusions of law under subparagraph (1), any participant may file, and shall serve on other participants, a reply thereto.

(m) *Proposed order.* (1) After the conclusion of the hearing and after the filings under paragraph (l) (1) and (2), the presiding officer shall issue a decision and proposed order based on findings of fact affirming, modifying, or vacating the contested order or directing other appropriate relief. The proposed order shall be based on the entire record before the presiding officer, including the record of prior proceedings certified by the Secretary.

(2) The presiding officer shall certify and file with the Secretary of the Commission, for the Commission, a copy of the record in the proceedings, including the proposed order.

(3) Participants may, within 15 days of issuance of the proposed order of the presiding officer, file with the Secretary of the Commission, for the Commission, written comments on any rulings of the presiding officer and the decision and proposed order.

(n) *Commission action.* The Commission shall upon consideration of the entire record and the proposed order issue a final order affirming, modifying, or vacating the contested order or directing other appropriate relief. The Commission shall serve the final order on all participants.

(o) *Ex parte communications.* The provisions of § 1.4(d) of this subpart shall apply to proceedings pursuant to this section, commencing at the time the Secretary issues a proposed remedial order under 10 CFR 205.192, an interim remedial order for immediate compliance under 10 CFR 205.199D, or a proposed order of disallowance under 10 CFR 205.199E, as if proceedings were contested on-the-record proceedings pending before the Commission.

(p) *Withdrawal of petition for review.* (1) At any time, including after a hearing has been held or convened, the petitioner may submit to the presiding officer, and serve on other participants in the proceeding, a withdrawal of the petition for review of the contested order. The presiding officer shall thereupon issue, and serve all participants, an order terminating the proceeding conducted pursuant to this section, which order shall be effective 10 days after issuance.

(2) Termination of the proceeding under subparagraph (1) may be appealed to the Commission, within 10 days after issuance of the termination order, except that if the Commission has not acted on an appeal within 30 days, it shall be deemed denied. The termination order shall be stayed pending the appeal. If the Commission rescinds the termination order, the proceeding shall continue in accordance with this section.

(q) *Sanctions.* Whenever it shall appear to the Commission that any person is engaged or about to engage in any acts or practices which constitute or will constitute a violation of any rule, regulation, or order made or imposed by the Commission or the presiding officer under this section, it may in its discretion bring an action in the proper court of the United States to enjoin such acts or practices and to enforce compliance with the order, and upon a proper showing, a permanent or temporary injunction or decree or restraining order shall be granted without bond. The Commission may transmit such evidence as may be available concerning such acts or practices to the Attorney General, who in his discretion, may institute the necessary criminal proceedings.

[FR Doc. 78-31702 Filed 11-8-78; 8:45 am]

[¶ 30,022]

43 F. R. 55756 (November 29, 1978)

[Docket No. RM79-4 Order 15]

PART 154—RATE SCHFDULES AND TARIFFS

PART 157—APPLICATIONS FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND ORDERS PERMITTING AND APPROVING ABANDONMENT UNDER SECTION 7 OF THE NATURAL GAS ACT

Amendments to the Commission's Regulations Relating to Independent Producer Filing Requirements

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Commission is amending its regulations relating to independent producer filing requirements to eliminate the requirement that producers file with the Commission a change in rate for each increase in rate resulting from the application of the inflation adjustment factor under the Natural Gas Policy Act of 1978 (NGPA). Without these amendments producers selling natural gas for which a maximum lawful price is established under section 104(b)(1)(A) or 106(a) of the NGPA would be required to make monthly rate change filings in order to collect those maximum lawful prices beginning December 1, 1978, or subsequent monthly inflation adjustments. Since the new maximum lawful prices are authorized by the NGPA, the Commission believes that the monthly filings are unnecessary, and is providing instead for a blanket filing for the maximum lawful price and escalations.

EFFECTIVE DATE: Immediately.

COMMENTS: December 1, 1978.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426 (Reference Docket No. RM79-4).

FOR FURTHER INFORMATION CONTACT:

Romulo Diaz, Office of the General Counsel, 825 North Capitol Street NE., Washington, D.C. 20426, 202-275-3771.

SUPPLEMENTARY INFORMATION:

Under sections 104 and 106(a) of the Natural Gas Policy Act of 1978 (NGPA), enacted on November 9, 1978, maximum lawful prices are prescribed for certain sales by producers of natural gas which is committed or dedicated to the interstate market as of November 8, 1978. Pursuant to section 101(b)(4)(C) of the NGPA, these maximum lawful prices will apply to deliveries of natural gas occurring on or after December 1, 1978, the first day of the first month following the date of enactment. Sections 104(b)(1)(A) and 106(a) of the NGPA permit these maximum lawful prices to escalate on a monthly basis in accordance with the inflation adjustment factor described in section 101(a) of the NGPA.

Under section 4 of the Natural Gas Act (NGA) and the Commission's current regulations in §§ 154.92 and 154.94, a producer selling natural gas under section 104(b)(1)(A) or 106(a) of the NGPA would not be permitted to collect the maximum lawful prices beginning December 1, 1978, unless he filed a change in rate pursuant to section 4(d) of the NGA and § 154.94 of the Commission's regulations. The maximum lawful prices under sections 104(b)(1)(A) and 106(a) of the NGPA increase each month in accordance with the inflation adjustment factor. Absent amendments to the Commission's regulations, a producer would be required to file a change in rate each month in order to charge and collect the additional increment in the maximum lawful price reflecting the inflation adjustment. Since these increases in price are authorized to be charged and collected by statute, the Commission believes that such monthly filings are unnecessary and that to continue to require them would impose needless administrative burdens and costs on both the producers and the Commission.

In order to provide an orderly transition from the producer rates currently in effect under the NGA to the new statutory pricing system prescribed under the NGPA for sales of dedicated natural gas, the Commission finds it necessary to amend its current regulations relating to producer filing requirements.

Under the amendments set forth herein, a producer that complies with the new blanket filing requirements would be permitted to charge and collect for each vintage or category of natural gas for which a just and reasonable price was in effect on April 20, 1977, the NGPA maximum lawful price for December 1, 1978, as well as the monthly inflation adjustment increases in subsequent months without having to make any further rate filings with the Commission. The blanket filing procedure implemented by this rulemaking will allow for a one-time filing and will relieve producers from current requirements, which, in the absence of this revision, would compel an estimated 200,000 filings per year.

An independent producer may file a blanket affidavit under which he may collect any maximum lawful price, including periodic escalations, which is applicable under section 104(b)(1)(A) or 106(a) of the NGPA and to which he is entitled on the basis of having qualified under the NGA for a base rate. (Section 104(b)(1)(A) of the NGPA permits collection of the just and reasonable rate in effect under the NGA on April 20, 1977, adjusted for inflation. Section 106(a) prescribes the rate for interstate rollover contracts.) "Base rate" is defined as a just and reasonable rate under the NGA applicable to a first sale of natural gas. A producer has established qualification for the base rate if he has made an initial rate filing or change of rate filing with the Commission under § 154.92 or § 154.94 of the regulations to collect such base rate, if collection of the filed rate is permissible under the applicable sales contract, and if the rate filing has taken effect. An initial rate filing takes effect when the filing has been accepted by the Commission. A rate change filing takes effect on the thirtieth day after the date of filing or any later effective date specified in the filing, unless such filing has been suspended or rejected.

A blanket affidavit covers both first sales listed in the affidavit for which qualification to collect the base rate has been established before the date of filing of the affidavit, and first sales for which qualification to collect the base rate is established after filing of the affidavit. In the latter case, the filing to establish the base rate must state that the sale will be covered by the blanket affidavit.

If a blanket affidavit filed before December 30, 1978, covers a first sale, it is effective with respect to deliveries, pursuant to that first sale, beginning on December 1, 1978. An affidavit filed on or after December 30, 1978, is effective with respect to deliveries, pursuant to a covered first sale, beginning on the date of filing of the affidavit. However, in neither case may an affidavit authorize collection of an NGPA rate prior to establishment of qualification to collect the base rate.

A blanket affidavit is deemed to be a notice of change of rate for purposes of section 4(d) of the NGA. The form of the affidavit is set out in the regulation. However, when the base rate for sales under a particular rate schedule changes, a rate change filing pursuant to § 154.94 will still be required before the new rate may be charged.

Certain natural gas which is committed or dedicated to the interstate market as of November 8, 1978, is subject to the interim collection provisions of section 503(e) of the NGPA. Under the amendments, the filing requirements imposed by that section shall satisfy any and all filing and notice requirements imposed by section 4(d) of the NGA and §§ 154.92 and 154.94 of the Commission's regulations. Section 503(e) of the NGPA indicates the intent of Congress to permit the prices prescribed in the NGPA and subject to the interim collection authority to become effective in accordance with the filing requirements imposed by that section. Therefore, to the extent that such filing requirements effect a waiver of the requirement in section 4(d) of the NGA and the Commission's regulations that publication be made thirty days prior to the effective date of such filing, good cause exists to waive such requirement.

Finally, § 157.40 of the regulations is amended herein to provide that small producers may charge the rate prescribed in sections 104(b)(1)(A) or 106(a) of the NGPA pursuant to the blanket certificate provided for in § 157.40(b).

The Commission is making this amendment effective upon the date of issuance of this order upon a finding that good cause exists to proceed without compliance with the notice, public procedure, and effective date provisions of 5 U.S.C. 553. The Commission is concerned that unless it makes these changes in its filing requirements immediately effective, producers will make unnecessary filings, under the previously established rules, between the date of enactment of the NGPA and the effective date of the new requirements. A delay in the effective date of these amendments would only lead to a disruptive transition from the pricing rules established under the NGA and those prescribed under the NGPA and result in needless administrative burdens and costs. For these reasons, the Commission has found it necessary to make these amendments effective upon the issuance of this order.

WRITTEN COMMENT PROCEDURES

Although these amendments are being made effective immediately, interested persons are invited to submit written comments, data, views or arguments with respect to the amendments. An original and 14 copies should be filed with the Secretary of the Commission. All comments received prior to December 1, 1978, will be considered by the Commission, and if appropriate, further revisions will be made. All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, 825 North Capitol Street NE., Washington, D.C. 20426, during regular business hours. Comments should be submitted to the Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, and should reference Docket No. RM79-4.

(Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.*, Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267.)

In consideration of the foregoing, Parts 154 and 157 of Subchapter E, Chapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective immediately.

By the Commission.

KENNETH F. PLUMB,
Secretary.

1. Section 157.40 is amended in paragraph (c) by adding a new subparagraph (6) to read as follows:

§ 157.40 Exemption of small producers from certain filing requirements.

* * * * *

(c) * * *

(6) All sales of natural gas by small producers for resale in interstate commerce which are subject to a maximum lawful price under section 104(b)(1)(A) or 106(a) of the Natural Gas Policy Act of 1978, shall be made at a price which does not exceed the applicable maximum lawful price under such section.

2. Section 154.94 is amended in the first sentence of paragraph (b) by striking out "Every" and inserting in lieu thereof the phrase "Except as provided in paragraphs (h) and (i) of this section, every", and is amended by adding new paragraphs (h) and (i), to read as follows:

§ 154.94 Changes in rate schedules.

* * * * *

(h) *Blanket filing.*—(1) *General rule.* An independent producer may file a blanket affidavit under this paragraph under which he may collect any maximum lawful price (including periodic escalations) which is applicable under section 104(b)(1)(A) or 106(a) of the Natural Gas Policy Act of 1978 (NGPA), and to which he is entitled on the basis of having qualified under the Natural Gas Act (NGA) for a base rate. Such maximum lawful price may be collected only in accordance with this paragraph.

(2) *Base rate.* For purposes of this paragraph:

(i) *Definition.* "Base rate" means a just and reasonable rate under the NGA applicable to a first sale of natural gas.

(ii) *Establishment of base rate.* An independent producer has established qualification for a base rate if: (A) He has made a rate filing with the Commission under § 154.92 or the preceding paragraphs of this section to collect such base rate; (B) such rate filing has taken effect; and (C) collection of such rate is permissible under the applicable sales contract.

(iii) *Date of base rate.* An initial rate filing under § 154.92 to collect a base rate has taken effect if such filing has been accepted by the Commission. A rate change filing under the preceding paragraphs of this section to collect a base rate takes effect on the thirtieth day after the date of filing (or any later effective date specified in the filing), unless such filing has been suspended or rejected.

(3) *Sales covered by affidavit.* An affidavit under paragraph (1) covers:

(i) Any first sale for which qualification to collect the base rate has been established before the date of filing of the affidavit, if such first sale is listed in the affidavit, and

(ii) Any first sale for which qualification to collect the base rate is established on or after the date of filing of the affidavit, if the filing to establish the base rate states that upon establishment of qualification for the base rate, the first sale will be covered by such affidavit.

(4) *Effective date of coverage under affidavit.* (i) An affidavit filed before December 30, 1978, is effective with respect to deliveries, pursuant to a first sale, beginning at the later of December 1, 1978, or the date of qualification of such first sale for the base rate.

(ii) An affidavit filed on or after December 30, 1978, is effective with respect to deliveries, pursuant to a first sale, beginning at the later of the date of qualification of such first sale for the base rate or the date of filing of the affidavit.

(5) *Effect of affidavit.* An affidavit filed under this paragraph shall be deemed to be a notice of change of rate for purposes of section 4(d) of the NGA. A filing made under this paragraph does not constitute a waiver of the right to apply for a higher rate under sections 104(b)(2) or 106(c) of the NGPA.

(6) *Form.* Any affidavit filed under subparagraph (1) shall be subscribed in accordance with § 1.16(a) of this chapter (except that § 1.16(a)(1)(iv) shall not apply). The form for such affidavit appears as Appendix A to this section. Concurrently with any filing made under this paragraph, the filing party must serve each affected purchaser with a copy of the affidavit.

(i) *Interim Collections.* Compliance with the filing requirements imposed by section 503(e) of the NGPA shall be deemed to satisfy the requirements of paragraph (b) of this section and section 4(d) of the NGA for sales of natural gas subject to section 503(c) of the NGPA. The 30 day notice otherwise required by section 4(d) of the NGA is waived.

APPENDIX A TO § 154.94

BLANKET AFFIDAVIT FILING UNDER § 154.94(h)

———— (the affiant) certifies that he is ———— (exact legal title or capacity of the affiant) of ———— (filing party) and, that:

(1) Under 18 CFR 154.94(h) he is entitled, and intends, to collect a maximum lawful price (including periodic escalations) under section 104(b)(1)(A) or 106(a) of the Natural Gas Policy Act of 1978 (NGPA) for each of the sales identified in the form attached as Exhibit A to his affidavit; and

(2) He will notify the Commission that additional first sales are covered by this affidavit in accordance with the requirements of § 154.94(h).

The undersigned swears or affirms that with respect to each rate filing under 18 CFR 154.92 or 154.94 which is identified in Exhibit A and on which he relies to collect the applicable price under this affidavit, he has made a diligent inquiry of individuals with personal knowledge of the facts contained in such filing and has determined after such inquiry that all statements made in such filing are true and accurate to the best of his knowledge, information and belief concerning, among other things, the factors relating to the eligibility to charge the rates therein, and that he has examined the prices to be charged under the NGPA for sales covered by this affidavit and found them to be in accordance with sections 104(b)(1)(A) and 106(a) of the NGPA.

Signature ————————

EXHIBIT A

Respondent name and code ——————

Rate schedule No.	Buyer name	Applicable just and reasonable rate previously established under NGA	Applicable NGPA rate	Effective date of rate establishment

INSTRUCTIONS FOR COMPLETING EXHIBIT A

I. *General Instructions.* Exhibit A shall be attached to the affidavit filed pursuant to § 154.94(h)(1) to identify those sales that qualify for the maximum lawful price permitted under §§ 104 or 106(a) of the NGPA. Where necessary, the list may be continued on succeeding pages in the same form. An affidavit and Exhibit A thereto may be filed in conjunction with a qualifying initial service application and should be attached to the billing statement filed therewith.

II. *Specific Instructions. Respondent Name and Code:* Enter the name of the respondent and the code, if any, assigned to the respondent from the publication entitled Buyer/Seller Codes.

FERC Rate Schedule Number: Enter the rate schedule number assigned by the FERC. If none, enter the contract date.

Buyer Name: Enter the buyer name.

Applicable Just and Reasonable Rate Previously Established Under NGA: Enter the base rate (Mcf at 14.73 psia) reflected in Data Field 24 of the last Schedule 507 submitted for the vintage involved. Where the last Schedule 507 was submitted for initial billing statement purposes, enter the base rate reflected in Data Field 23 thereof.

Applicable NGPA Rate: Enter the maximum lawful MMBtu ceiling price (excluding taxes) for the vintage involved.

Effective Date of the Rate Establishment: Enter the proposed effective date of the NGPA rate.

[FR Doc. 78-33394 Filed 11-28-78; 8:45 am]

[¶ 30,023]

43 F. R. 56031 (November 30, 1978)

PART 154—RATE SCHEDULES AND TARIFFS

Final Regulation Requiring Jurisdictional Pipelines To Elect Either Adoption of PGA Clauses or General Section 4 Rate Filings To Recover Changes in the Cost of Purchased Gas

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: This final rule requires natural gas pipeline companies to elect for three year periods whether to recover changes in purchased gas cost through a purchased gas adjustment provision (PGA Clause) or a general section 4 rate filing. The regulation is necessary in order to reduce the financial and administrative burden associated with the frequency of filings for changes in purchased gas cost. The effect of this regulation is to prevent companies which choose to include a PGA clause in their tariff from recovering changes in purchased gas cost in a section 4 filing. It also prohibits a company which chooses to recover changes in purchased gas costs in general section 4 rate filings from recovering changes in purchased gas cost through a PGA clause.

EFFECTIVE DATE: December 1, 1978.

FOR FURTHER INFORMATION CONTACT:

MaryJane Reynolds, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 275-4283.

Regulations of the Federal Energy Regulatory Commission (Commission) under the Natural Gas Act permit the inclusion of a purchased gas adjustment provision (PGA clause) in natural gas pipeline companies' tariffs under certain specified conditions. PGA clauses were originally permitted to avoid frequent consideration of rate increase filings caused by the constantly rising cost of purchased gas. (See Orders 452 & 452-A, 47 FPC 1049 (1972) and 47 FPC 1510 (1972) respectively.) However, the number and frequency of PGA filings reached such a magnitude that they imposed an undue financial and administrative burden upon the pipeline companies, their customers, the Commission staff, the state Commissions and ultimate consumers. In Order No. 13, the Commission took action to reduce this burden by limiting the filing of future PGA rate changes to two per year and prescribing semi-annual filing dates for each pipeline company (43 FR 50167, October 27, 1978). The intended reduction in filings, however, would not be accomplished if pipeline companies responded to the order by including changes in purchased gas cost in general section 4 rate filings. The Commission therefore proposed a regulation in Docket No. RM79-1 to require jurisdictional pipeline companies to elect, for periods of three years whether to reflect changes in purchased gas cost in the PGA clause or in general section 4 rate filings under § 154.63 (43 FR 50191, October 27, 1978).

Interested parties were invited to submit comments on the proposed rule by November 20, 1978. Six timely comments were received from seven natural gas pipeline companies;[1] three late comments were also received. All parties supported the proposed rule, except the jointly filing pipelines. Specific points raised in the comments have been incorporated in the final regulation.

Other comments are discussed in the summary of the final regulation.

SUMMARY OF THE FINAL REGULATION

The regulation adopted today amends 18 CFR 154.38(d)(4) to require each interstate pipeline company to make an election whether to recoup all changes in purchased gas cost pursuant to its PGA clause or pursuant to a general section 4 rate filing. The election is binding for a three year period.

A company which selects the PGA option will not be permitted to include changes in purchased gas cost in general section 4 rate filings made during the period that the PGA option is in effect. However, a company which elects the PGA option, if confronted with severe financial consequences due to the election, may request a waiver from the Commission and file a general section 4 rate increase which includes changes in purchased gas cost.

Only one interested party challenges the Commission's authority to require an election of this type. It asserts that the Commission may not limit the rights of a natural gas pipeline company under the Natural Gas Act to file a general section 4 rate increase. Nothing in the election rule limits the right of any company to file a section 4 rate increase. The choice between section 4 and PGA treatment for purchased gas cost for each option period is exclusively at the discretion of the company. Furthermore, a company which chooses the PGA option may make section 4 filings to reflect changes in all costs other than purchased gas cost. Therefore in the Commission's view the election procedure in no way limits a company's section 4 rights.

The Natural Gas Act does not require that the Commission provide for PGA clauses and no pipeline has a statutory right to collect purchased gas cost through a PGA clause. However, the Commission believes that a company which chooses the PGA election is adequately protected even though it foregoes the right to file a section 4 rate increase to reflect changes in purchased gas cost. Specifically, the PGA procedure allows the annualization of changes occurring during the 12 month historical test period including significant changes in purchase patterns. Moreover, amounts in the deferred account reflecting unrecovered purchased gas cost may now include carrying charges. Most importantly, if a company finds that the carrying charges are insufficient to protect its financial integrity, it may seek a waiver from the Commission which would allow it to include changes in purchased gas cost in a section 4 rate filing notwithstanding its currently effective PGA clause.

A. ELECTION PROCEDURE.

Natural gas pipeline companies may elect once every three years which method will govern their method of recovery of changes in purchased gas costs for the three year period designated the "election period." Comments suggested that the election procedure should be detailed more fully in the regulations. The final rule has been modified accordingly.

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[1] A joint filing was made by two pipelines.

Companies need not notify the Commission of their election. Any company with an effective PGA clause in its tariff on December 1, 1978, will be deemed to have chosen the PGA option. However, for this first election period a company with a PGA clause in effect on December 1, 1978, which chooses the non-PGA option must notify the Commission of its non-PGA option on or before December 1 but has until December 15 to file conforming tariff sheets with a proposed effective date of January 1, 1979. Thereafter if a different option is chosen for a subsequent election period, tariff sheets necessary to implement the option must be filed by December 1 preceding the election period beginning on January 1. Any company which does not file amended tariff sheets reflecting a changed option will be deemed to have chosen to continue the option of the previous election period.

B. EFFECT OF THE ELECTION.

A company which has selected the PGA option shall file for changes in its purchased gas cost exclusively through its PGA clause for the entire election period. It may not file tariff sheets eliminating the effectiveness of its PGA clause during that period. Nor may it include changes in its purchased gas cost in any general section 4 filing during that election period unless it has received a waiver from the Commission.

The final rule has been clarified to assure that any company which chooses the PGA option for the first election period, beginning January 1, 1979, may not include changes in its purchased gas cost in any general section 4 filing during December 1978. The Commission has determined that this restriction is essential to the fundamental purpose of the rule. It will avoid numerous section 4 filings by companies electing the PGA option and will provide an orderly passthrough of the increases in purchased gas cost.

C. PURCHASED GAS COST COVERED BY THE ELECTION

The rule provides that any company which elects the PGA option may not include in a general section 4 rate filing any changes in purchased gas cost other than those which are included in rate adjustments filed pursuant to a PGA clause. The proposed rule failed to reflect the amendment to purchased gas cost adopted in Order 567, —— F.P.C. —— (1977). That order specified that with respect to pipeline production, only those purchased gas costs which qualify for and are being afforded area or nationwide rate treatment may be included in the PGA.

The final rule includes the change adopted in Order 567 and, in addition, allows for the inclusion of pipeline production which is not subject to an area or nationwide rate but is treated as though it were produced by an independent producer.

It was also suggested by one pipeline that the definition be amended to include new pipeline supplies (contractual daily delivery obligations) in the PGA without prior Commission approval. This proposition was previously addressed and rejected by the Commission in Order 452-A. No change in circumstances has been presented which would warrant a modification of the Commission policy expressed in Opinion 452-A. Accordingly, the definition is not being modified to include new pipeline supplies (contractual daily delivery obligations) prior to Commission approval.

D. WAVIERS

It is the intent of the Commission that companies electing the PGA option not file section 4 rate increases to reflect changes in purchased gas cost included in the PGA clause. However, the Commission recognizes that there may be a few isolated and unforeseeable instances where the pipeline (1) is unable to arrange for financing of the balances being carried in the deferred account (Account 191) or (2) is not able to earn its overall rate of return last allowed by the Commission because of the magnitude of the balances in the deferred account (Account 191) and a significant difference between the costs of financing the deferred amounts and the carrying charges allowed pursuant to § 154.38(d)(4)(iv)(c). In those cases, a waiver may be requested when the company files a section 4 rate case to include changes in purchased gas cost. If the waiver is granted, then changes in purchased gas cost would be included in the section 4 proceeding. If the waiver is denied, the tariff sheets filed with the section 4 proceeding will be rejected and new tariff sheets, excluding changes in purchased gas cost will have to be filed.

Several parties have commented that the grounds for waiver are too narrow. However it is the Commission's intention that those companies choosing the PGA option be prevented from including changes in purchased gas cost in a general section 4 rate filing except under the most unusual circumstances.

Thus, the waiver standards are intended to provide relief only in very extraordinary cases. Moreover, the Commission believes that, in light of the flexibility allowed in PGA filings, including the newly promulgated provision allowing carrying charges, that the grounds for waiver, as promulgated, are appropriate.

One party commented that the standards for waiver were not sufficiently delineated in the proposed rule. The final rule sets forth the second test in more detail. The second test is two-fold. First the company must show that it is unable to earn its allowed rate of return. The allowed rate of return would include a rate established in a settled case which was submitted to and approved by the Commission as well as in a rate case in which the Commission had a fully litigated record upon which to base its final decision on the rate of return issue. Second, if a company is not meeting its allowed rate or return, it must then show that its not doing so is due to the magnitude of the balances in the deferred account (Account 191) and that finance charges substantially exceed carrying charges. This difference is a function of both interest rates and the volumes of gas covered by the PGA.

E. INTERACTION BETWEEN THE PGA CLAUSE AND SECTION 4 FILINGS

The rule specifically provides that changes in purchased gas cost covered by a PGA may not be included in a section 4 rate filing. Consequently the conforming amendments to § 154.63 have been adopted with the changes discussed herein. Pursuant to the final rule, § 154.63, a company which makes a section 4 rate filing shall reflect the "total system weighted average current unit cost of gas" as reflected in its currently effective PGA clause. This language merely clarifies that the "unit cost" used in the proposed rule was intended to be a single unit cost reflecting all changes in purchased gas cost reflected in the PGA tariff rates.

The comments raised several points concerning section 4 rate filings by companies which select the PGA option which merit comment.

First, under the PGA option, companies are allowed both to annualize gas purchase cost and to reflect changes in supply patterns. Hence in making a section 4 filing a company which has selected the PGA option must calculate a single total system weighted average current unit cost of gas from data contained in its currently effective PGA clause. This unit figure excludes any surcharge collected under the PGA because the surcharge does not reflect current cost of purchased gas. In filing a section 4 rate increase the company may make adjustments in purchase and sales volumes but it may not adjust the total system weighted average current unit cost of gas reflected in the effective PGA to reflect estimated changes in purchase patterns. Consequently, the company in estimating the total adjusted costs must multiply the PGA unit cost by the projected purchased gas volumes.

Second, several companies suggested that for § 154.63 filings the PGA unit cost be the one effective at the time the section 4 filing is made, rather than the PGA rate last approved by the Commission as contemplated in the proposed rulemaking. The suggestion has been adopted in the final rule. This will allow use of the most current PGA rate and yet will not result in the overcharge of any customer because the PGA adjustment which has been set for hearing, but made effective, is subject to refund.

Third, one party is concerned that the Commission may no longer permit amendments to general section 4 rate case suspended rates to reflect PGA adjustments occurring during the suspension period. The concern is unfounded. The Commission does not intend to modify its existing policy with respect to PGA adjustments occurring during the suspension period in a section 4 rate case.

Finally, one party has suggested that because of the exclusion of changes in purchased gas cost from a section 4 filing by a company which has chosen the PGA option, such a company will have no mechanism by which to establish a new base cost of purchased gas. Section 154.38(d)(4)(vi) has no provision for the establishment of a base cost of purchased gas, but it does require establishment of base tariff rates. The rule promulgated today provides that every company which elects the PGA option shall include in its restated base tariff rates filed either pursuant to § 154.38(d)(4)(vi) or § 154.63 its total system weighted average current unit cost of gas reflected in its currently effective PGA rate adjustment. The effective total system weighted average current unit cost of gas represents a company's base cost of purchased gas.

FINDINGS

(1) For the reasons set forth, the Commission finds that it is appropriate and in the public interest in administering the Natural Gas Act to adopt these amendments;

(2) For good cause as more fully described herein, the Commission finds that notice and comment on those provisions of the amendment adopted today which were not included in the proposed rule are impracticable and contrary to the public interest;

(3) In view of the purpose, intent and effect of the amendments, good cause exists for making them effective on December 1, 1978.

(Natural Gas Act (15 U.S.C. 717 *et seq.*) Administrative Procedure Act (5 U.S.C. 553), Department of Energy Organization Act (42 U.S.C. 7101, *et seq.*), and E.O. 12009, 42 FR 46267.)

CONCLUSION

In consideration of the foregoing, Part 154, Chapter I of Title 18, Code of Federal Regulations, is amended as set forth below, effective December 1, 1978.

By the Commission.

LOIS D. CASHELL,
Acting Secretary.

1. Section 154.38 is amended in subparagraph (4) of paragraph (d) by revising the introductory language and by adding a new subdivision (ix) to read as follows:

§ 154.38 Composition of rate schedule.

* * * * *

(d) *Statement of rate.* * * *

(4) A natural gas pipeline company may flow through changes in its cost of purchased gas [1] pursuant to a purchased gas adjustment clause (PGA clause). The proposed clause must be filed with the Commission and shall not be effective until approved by the Commission. No request for approval of a PGA clause will be considered unless the proposed clause meets the terms and conditions specified in subdivisions (i) through (viii) of this subparagraph. Any PGA clause approved by the Commission is subject to the conditions in subdivision (ix) of this subparagraph.

* * * * *

(ix) *Election of a PGA clause.* A natural gas pipeline company shall elect once every three years whether to recover all changes in purchased gas costs either through general rate filings made under § 154.63 or through filings made under a PGA clause prescribed in this paragraph.

(*a*) *Procedure for election.* For purposes of this paragraph, "election period" means a three year calendar period commencing on January 1, of every third year. The first election period commences on January 1, 1979. The election for an election period must be made on or before the first day of the December preceding the new election period and is binding for the entire election. Any company which has a PGA clause in its tariff on December 1, 1978, shall be considered to have elected to recover its changes in purchased gas cost exclusively through the PGA clause. However, such a company with a PGA clause in its tariff on December 1, 1978 which chooses not to use the PGA clause must notify the Commission by December 1, 1978 that it has elected not to recover any of its changes in purchased gas cost under a PGA clause. It shall file revised tariff sheets eliminating the PGA clause from its tariff, by December 15, 1978 to become effective January 1, 1979. Waiver of the notice requirements in § 154.22 is hereby granted to permit such conforming tariff sheets to become effective January 1, 1979. Any company which elects the PGA clause option pursuant to this paragraph may terminate its PGA clause effective as of the next election period by filing revised tariff sheets eliminating the PGA clause from its tariff. Such tariff sheets must be filed on or before December 1, preceding a new election period to become effective on the first January 1 of the new election period. If a company does not make such a filing, it shall be considered to have elected to renew its PGA clause option for the new election period. A company which has chosen the non-PGA option for an election period may file revised tariff sheets implementing the PGA clause option for the next election period. Such tariff sheets must be filed on or before the December 1 preceding a new election period to make the PGA clause effective on the first January 1 of that election period.

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[1] For the purposes of this paragraph, purchased gas cost represents the cost of wellhead purchases, field line purchases, plant outlet purchases, transmission line purchases, and pipeline production that qualifies for and is being afforded area or nationwide rate treatment or is otherwise being afforded rate treatment as though the gas were being produced by an independent producer. Nonconcurrent exchange transactions may be reflected as a cost of purchased gas. If a company has underground storage, the cost of purchased gas included in Accounts 800, 801, 802, and 803, and where applicable, Account 806, shall be debited or credited to reflect the net injections or withdrawals from underground storage. This adjustment shall be prorated between pipeline and producer supply. New pipeline supplies (contractual daily delivery obligations) and liquified natural gas, synthetic natural gas, gas from coal gasification, and pipeline production when priced on a cost of service basis pursuant to Commission authorization shall not be reflected in a PGA clause without prior Commission approval.

(*b*) *PGA clause option.* Any company which has elected the PGA clause option for the first election period, beginning on January 1, 1979, may not include any changes in purchased gas cost in a general section 4 rate filing made under § 154.63 and which is filed in December 1978. Thereafter, during an election period for which a company has elected the PGA option, it shall file for changes in its purchased gas cost exclusively through its PGA clause. The company may not file tariff sheets eliminating its PGA clause from its effective tariff during the election period and may not include any changes in its purchased gas cost in a general section 4 rate filing made under § 154.63, during the election period for which the PGA clause is in effect: *Provided, however,* That a company may request the Commission for a waiver of the election and if granted may include changes in purchased gas cost in a general section 4 rate filing made under § 154.63.

To receive a waiver, the company must demonstrate that (*1*) it is unable to arrange for financing of the balances being carried in the deferred account (Account No. 191), or (*2*) is not able to earn its overall rate of return last allowed by the Commission because of the magnitude of the balances in the deferred account (Account No. 191) and a significant difference between the costs of financing the deferred amounts and the carrying charges allowed under paragraph (d)(4)(iv)(c) of this section.

(*c*) *Non-PGA option.* During an election period for which the company has elected the non-PGA option, a company shall file for changes in purchased gas cost exclusively in a general section 4 rate filing made under § 154.63. The company may not file tariff sheets to include a PGA clause in its effective tariff during that election period.

2. Section 154.63 is amended by revising subparagraphs (3) and (4) of paragraph (b) and by revising Schedule H(1)-3 of paragraph (f) to read as follows:

§ 154.63 Changes in a tariff, executed service agreement or part thereof

* * * * *

(b) *Material to be submitted.* * * *

(3) *Major rate increase.* Class A companies (as defined in Subchapter F, Uniform System of Accounts for Natural Gas Companies, of this chapter) shall submit, in addition to the material required by subparagraph (1) of this paragraph, Statements A to M inclusive and O and P described in paragraph (f) of this section. Class B, C,

and D companies, defined as above, shall file only Statements L, M, N, O, and P. Statement P, which is required to be submitted by all classes of companies, may be furnished not later than 15 days after the date of the filing. A natural gas company filing another major increase in rates or charges within a period of twelve months after the date of filing of Statements A through M and O and P or after the end of the test period used therein including the period of adjustments shown on Statements A through M may submit for such other increase Statements L, M, and N in lieu of Statements A through M if the proposed new rate increase is filed to compensate only for an increase in the cost of purchased gas and there has been no material change in the company's facilities, sales volumes, and cost of service other than cost of purchased gas since such prior rate increase was filed. However, pipelines with Commission approved PGA clauses conforming to § 154.38(d)(4) shall not be permitted to include changes in purchased gas cost in filings made under this subparagraph unless they have received a waiver of their PGA election under § 154.38(d)(4). A pipeline with an effective Commission approved PGA clauses shall reflect in any filing made pursuant to this subparagraph the total system weighted average current unit cost of purchased gas reflected in the pipeline's latest effective PGA rate adjustment, unless the pipeline has received a waiver of its PGA election under § 154.38(d)(4).

(4) *Minor rate increase or rate decrease.* Only Statement L through N need be filed in addition to the material required by subparagraph (1) of this paragraph. (Statements L through N are not required to make effective rate changes or tariff provisions ordered by the Commission). A pipeline with an effective Commission approved PGA clause conforming to § 154.38(d)(4) shall not be permitted to include changes in purchased gas costs in rate filings made pursuant to this subparagraph unless the pipeline has received a waiver of its PGA election under § 154.38(d)(4). A pipeline with an effective Commission approved PGA clause shall reflect in any filing made under this subparagraph the total system weighted average current unit cost of purchased gas reflected in the pipeline's latest effective PGA rate adjustment, unless the pipeline has received a waiver of its PGA election under § 154.38(d)(4). However, the pipeline may adjust the purchased gas volumes.

* * * * *

(f) *Description of statements.* * * *

Schedule H(1)-3, a schedule showing either: (a) In the case of a pipeline which has a Commission approved PGA clause in its tariff, its total system weighted average current unit cost of purchased gas reflected in the pipeline's latest effective PGA rate adjustment. However, the pipeline may adjust its purchased gas volumes as provided in (b) hereof; or (b) in the case of a pipeline which does not have a Commission approved PGA clause in its tariff or in the case of a pipeline which has a Commission approved PGA clause but obtains a waiver of its PGA clause election under § 154.38(d)(4), the total annual cost of gas purchased for the 12 months of actual experience, the adjustments thereto, and the total adjusted cost for test period, with the data grouped by States and producing areas and detailed by contract or rate schedule designation, field, volumes in Mcf at a common pressure base and price in total for the contracts or rate schedules under which actual or adjusted volumes exceed 1,000,000 Mcf annually. Field purchases under rate schedules where the actual or adjusted volumes are less than 1,000,000 Mcf annually may be grouped by field or producing area. Purchases from pipelines in any volume shall be shown in full detail by rate schedule including splits between demand and commodity charges.

In the event adjustments are made to the volumes of gas taken from any source during the 12 months of actual experience, a detailed explanation and data in support of the adjusted volumes shall be furnished. No adjustments are to be made to reflect the attachment of new gas supplies unless both the filing company and the supplier have each obtained the required permanent or temporary certificates of public convenience and necessity and the necessary facilities by both are or will have been in operation during the test period.

In the event the adjustments to volume aggregate more than 10 percent of the total volume of gas purchased during the 12 months of actual experience, and are due to change in gas purchase pattern or additional gas supply, the minimum take-or-pay-for quantities for each source of supply, applicable at the end of the test year period, and the reasons for making such adjustments shall be submitted.

If the company purchases and sells gas under exchange agreements, the method of recording on books, total gross volumes exchanged, net dollar amounts involved and details of each major exchange shall be submitted.

[FR Doc. 78-33589 Filed 11-29-78; 8:45 am]

[¶ 30,024]

43 F. R. 56035 (November 30, 1978)

SUBCHAPTER G—APPROVED FORMS, NATURAL GAS ACT

[Order No. 526-E; Docket No. RM74-16]

PART 260—STATEMENTS AND REPORTS (SCHEDULES)

Order To Postpone Certain Filing Dates of Required Schedules

NOVEMBER 22, 1978.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Order to postpone certain filing dates of required Form 40 schedules.

SUMMARY: Order No. 526-E of the Federal Energy Regulatory Commission amends Order No. 526-D (Docket No. RM74-16) with regard to the filing date of Form 40 Schedules for Report Year 1977, deferring that date until further notice. In addition, the order suspends, until further notice, the filing of Form 40 for report years subsequent to 1977. This action is being taken to prevent duplicate reporting pending OMB approval of the Energy Information Administration's proposed Form EIA-23.

EFFECTIVE DATE: November 22, 1978.

FOR FURTHER INFORMATION CONTACT:

John Conway, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 275-4296.

On July 31, 1978, this Commission issued its Order No. 526-D (Docket No. RM74-16) which amended § 260.13(d) of its regulations to extend the filing date for Form No. 40 schedules for Report Year 1977 from September 1, 1978 to December 1, 1978. This order modifies Order 526-D to suspend until further notice the filing date for Report Year 1977. In addition, this order also postpones until further notice that part of § 260.13(d) (as amended) of the Commission's regulations respecting the filing of Form No. 40 for report years following 1977.[1]

Currently, the Office of Management and Budget (OMB) is reviewing Energy Information Administration (EIA) Form EIA-23, a new form designed to require similar information now required by Form No. 40. In addition, the OMB has determined that it will not consider FPC Form No. 40, transmitted to the OMB for clearance on June 12, 1978, unless events occur that would prevent or materially delay the implementation of Form EIA-23.

Pending the approval and implementation of Form EIA-23, or in the alternative OMB approval of FPC Form No. 40, the Commission has determined that there is a need to postpone the current December 1, 1978 filing deadline of FPC Form No. 40 for 1977 data. This determination is based upon the potential for the duplication of effort which may come about should the proposed Form EIA-23 be approved in the near future. For the same reason, the filing deadlines for data collected in years following 1977 should also be postponed. Balanced against this potential duplication is the need of the Commission for the data which Form No. 40 and Form EIA-23 are designed to collect. Accordingly, the Commission today orders that the filing requirements of Form No. 40 for 1977 and subsequent years be postponed until further Commission order. Upon approval of either FPC Form 40 or Form EIA-23, the Commission will expect filings to be made of data collected during 1977 and subsequent years to which this order applies.

This order does not affect filings required for years prior to 1977.

The Commission finds: (1) On its own motion, and for the reasons stated above, that the required filing dates for 1977 and subsequent years' reporting of Form No. 40 as set forth in the Commission's regulations should be modified as set forth herein.

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[1] This proceeding was commenced before the FPC. By the joint regulation of October 1, 1977 (10 CFR 1000.1), it was transferred to the FERC.

(2) The modification so made, to postpone these filing dates, is to minimize the potential for duplicative reporting pending action by the OMB.

(3) That for the reasons given above, and in that this order relieves a restriction previously imposed to the extent of postponing filing dates, good cause exists to dispense with notice and public procedures (5 U.S.C. § 553(b) (1977)); and this order may therefore be made effective immediately (5 U.S.C. § 553(d) (1977)).

The Commission orders: (A) The requirements of Section 260.13(d), Part 260, Subchapter G of Chapter I, Title 18 of the Code of Federal Regulations (as set forth in Order No. 526-C, issued February 17, 1978, and amended by Order No. 526-D, issued July 21, 1978) respecting the filing dates of FPC Form No. 40 for the calendar year ending December 31, 1977 and subsequent reporting years are postponed until further order by the Commission.

(B) The effective date of this order shall be the date of issuance.

(C) The Secretary shall cause prompt publication of this order to be made in the FEDERAL REGISTER.

By the Commission.

KENNETH F. PLUMB,
Secretary.

[FR Doc. 78-33670 Filed 11-29-78; 8:45 am]

[¶ 30,025]

43 F. R. 56220 (December 1, 1978)

PART 154—RATE SCHEDULES AND TARIFFS

Modification of Purchased Gas Cost Adjustment Clause Regulations

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Order No. 13-A issued in Docket No. R-406.

SUMMARY: Order amending Order No. 13 which amended the Federal Energy Regulatory Commission's purchased gas cost adjustment clause regulations to limit to two a year the number of purchased gas cost adjustment rate filings an interstate pipeline may make and to allow these pipelines to accrue and collect carrying charges on amounts carried in their deferred purchased gas costs accounts. Order No. 13-A denies rehearing of Order No. 13 and makes some clarifying modifications to that order.

EFFECTIVE DATE: Effective on January 1, 1979.

FOR FURTHER INFORMATION CONTACT:

Charles E. Bullock, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 (202)—275-4232.

On October 18, 1978, as amended by Errata Notice issued October 20, 1978, the Commission issued Order No. 13 which amended the purchased gas adjustment (PGA) clause regulations contained in § 154.38(d)(4) of the regulations to limit the number of PGA filings made by natural gas pipeline companies and to permit the collection of carrying charges accrued on balances carried in Account 191, Unrecovered Purchased Gas Costs. On November 3, 1978, the Public Service Commission of the State of New York (New York) filed an application for rehearing and clarification of Order No. 13. On November 17, 1978, Midwestern Gas Transmission Company (Midwestern) and Western Gas Interstate Company (Western) each filed an application for rehearing of Order No. 13. For the reasons stated below, the Commission shall grant in part and deny in part the applications for rehearing of Order No. 13. In addition, the Commission shall make some clarifying modifications to Order No. 13.

New York argues that Order No. 13 continues to treat the flow-through of pipeline supplier rate increases on a discriminatory basis from the flow-through of pipeline supplier refunds. Specifically, New York alleges that while carrying charges are permitted on positive balances in the deferred account, which result when the pipeline has undercollected its purchased gas costs, there are no similar interest provisions should negative balances occur, which result when the pipeline has overcollected its purchased gas costs. New York is particularly concerned about the alleged lack of interest provisions when negative balances result when a pipeline receives a lump sum refund from one of its pipeline suppliers resulting from the resolution of that pipeline supplier's general section 4 rate case.

New York's concerns are unfounded. Section 154.38(d)(4)(iv)(*b*) of the Regulations [1] provides for carrying charges on positive balances as well as interest amounts on negative balances at the current rate of interest on pipeline refunds prescribed by the Commission. Thus no discrimination will result between the treatment of positive and negative balances accrued in the deferred account.[2]

Finally, New York urges that the Commission substantially modify Order No. 13 to provide that pipeline supplier refunds received by a pipeline be flowed through within 30 days of the date they are received if they exceed $10,000,000 or 1% of the purchasing pipeline's jurisdictional revenues for the last calendar year, whichever is lower, in a manner consistent with the pattern of payment of the excess charges. New York argues that the distributor and direct industrial customers of a pipeline supplier making refunds from its general section 4 rate increase filing receive refunds sooner than the customers of that pipeline supplier's pipeline purchasers because the refunds are credited to the pipeline purchasers' Accounts 191. In addition, New York is concerned that the customers of the pipeline purchasers who receive the effect of these refunds may not receive them in proportion to the amount of excess charges they actually paid, subject to refund.

The Commission shall not adopt New York's suggested modification to Order No. 13. The alleged discrimination between the direct industrial and distributor customers versus the pipeline purchaser customers of a pipeline supplier is taken into account by the carrying charge and interest provisions governing balances in the pipeline purchaser's Account 191. Thus, the customers of the pipeline supplier will be adequately compensated for the time value of the refunds received by the pipeline purchaser from the pipeline supplier and placed in the pipeline purchaser's Account 191. In any event, New York's proposal to require all pipeline supplier refunds above a certain level to be flowed through on a lump sum, as-billed basis is beyond the scope of the Notice of Rulemaking in this docket. However, the Commission shall continue to monitor this issue and to determine whether future amendments to the PGA clause regulations are necessary.

Midwestern argues for a special exemption for its Northern Division to permit the simultaneous flow-through of major increases in its Canadian supplier rates. Midwestern indicates that it is willing to agree to a once a year PGA rate adjustment date (January 1) for Canadian supplier increases accrued in its Account 191 resulting from the fact that monthly payments are made to its Canadian supplier in Canadian, rather than U.S. dollars and the fact that volumes are purchased on a Btu, rather than an Mcf basis.[3] However, it alleges that it is concerned about the financial impact which may result from its having to carry a large increase in purchased gas costs in its Account 191 for any length of time.

Midwestern's request shall not be granted. Midwestern, like other pipelines, will be permitted to accrue and collect carrying charges on amounts carried in its Account 191. To the extent carrying charges do not adequately protect Midwestern, it may file a general section 4 rate increase case to reflect, among other things, changes in purchased gas costs if it can demonstrate the need for waiver, as described in more detail in Order No. *16* issued this day in Docket No. RM79-1.

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[1] New York correctly points out that the entire clause (iv) was erroneously referred to in Order No. 13 (mimeo p. 18, line 10) and in the Errata Notice (mimeo, p. 1, lines 2 and 5) as § 154.38(d)(4)(vi) rather than § 154.38(d)(4)(iv). That error will be corrected in this order.

[2] New York also alleges that in promulgating the new § 154.38(d)(4)(iv), the Commission erroneously did not delete the first paragraph of the old clause (iv). New York is correct and this error shall be corrected. The new clause (iv) was intended as a replacement for *all* of the language in the old clause (iv).

[3] Midwestern states that it has no objection to the January 1 and July 1 adjustment dates prescribed for it insofar as they affect flow-through of purchased gas costs by its Southern Division.

Western requests that its adjustment dates be changed from February 1 and August 1 *to* May 1 and November 1 so that it may better track changes in purchased gas costs flowed through by its major suppliers, El Paso Natural Gas Company (El Paso) and Colorado Interstate Gas Company (CIG) which have adjustment dates of April 1 and October 1; and October 1, respectively. For good cause shown, Western's request shall be granted.

For purposes of clarification, the Commission notes that filings made during the effectiveness of a pipeline's old PGA clause shall be governed by the *filing* dates in their old PGA clause even if the proposed effective date occurs after the pipeline's old PGA clause has expired. Similarly, filings made on or after the date the new PGA clause becomes effective shall be made in accordance with the procedures (including adjustment dates) prescribed by the new PGA clause.

Section 154.38(d)(4)(iv)(*b*) erroneously required that *all* pipelines must utilize Account 731.1 in conjunction with Account 191. The Uniform System of Accounts provides that only Class C and D pipelines use Account 731.1 and that Class A and B pipelines should use Account 805.1 in conjunction with Account 191. Section 154.38(d)(4)(iv)(*b*) will be amended to correct this error.

Order No. 13 also erroneously eliminated the requirement contained in the old § 154.38(d)(4)(iv)(*b*) of the PGA regulations which prescribed instructions for calculation of the surcharge to recover amounts accumulated in the pipeline company's Account 191. Accordingly, the revised § 154.38(d)(4)(iv) promulgated in Order No. 13 shall be amended in this order to reinstate those instructions.

For purposes of clarification, we shall republish the amendments to § 154.38(d)(4) as promulgated in Order No. 13 and the Errata Notice, as amended in the instant order.

(Natural Gas Act (15 U.S.C. 717c, g, i and o), Administrative Procedure Act (5 U.S.C. 553), Department of Energy Organization Act, (42 U.S.C. 7101, *et seq.*), and E.O. 12009, 42 F.R. 46267.

In consideration of the foregoing, Part 154, Chapter I of Title 18, The Code of Federal Regulations is amended as set forth below, to become effective January 1, 1979.

By the Commission.

LOIS D. CASHELL,
Acting Secretary.

1. Section 154 is amended in subparagraph (4) paragraph (d) by revising subdivision (iv) and by adding a new subdivision (viii) to read as follows:

§ 154.38 Composition of rate schedule.

* * * * *

(d) *Statement of rate.* * * *

(4) * * *

(iv)(*a*) Rate changes which reflect both the current cost of purchased gas and a revised surcharge to clear the amounts accrued in the deferred account for both producer and pipeline suppliers shall be computed and filed not more frequently than semi-annually. The PGA clause shall specify dates of adjustment as follows:

JANUARY 1, AND JULY 1

Alabama-Tennessee Natural Gas Company
East Tennessee Natural Gas Company
Chattanooga Gas Company, a Division of Jupiter Industries, Inc.
Granite State Gas Transmission, Inc.
Midwestern Gas Transmission Company
Sea Robin Pipeline Company
Southern Natural Gas Company
South Georgia Natural Gas Company
Tennessee Gas Pipeline Company, a Division of Tenneco, Inc.
Tennessee Natural Gas Lines, Inc.
United Gas Pipe Line Company
Distrigas of Massachusetts Corporation
Gas Gathering Corporation

FEBRUARY 1, AND AUGUST 1

Lawrenceburg Gas Transmission Corporation
Mid Louisiana Gas Company
National Fuel Gas Supply Corporation
Texas Eastern Transmission Corporation
Texas Gas Transmission Corporation
Utah Gas Service Company

MARCH 1, AND SEPTEMBER 1

Algonquin Gas Transmission Company
Columbia Gas Transmission Corporation
Consolidated Gas Supply Corporation
Eastern Shore Natural Gas Company
Mississippi River Transmission Corporation
Natural Gas Pipeline Company of America
North Penn Gas Company
Panhandle Eastern Pipe Line Company
Transcontinental Gas Pipe Line Corporation
Trunkline Gas Company

APRIL 1, AND OCTOBER 1

Arkansas Louisiana Gas Company
El Paso Natural Gas Company
Florida Gas Transmission Company
Mountain Fuel Supply Company
Northwest Pipeline Corporation
Oklahoma Natural Gas Gathering Corporation
Pacific Interstate Transmission Company
Raton Natural Gas Company
Southwest Gas Corporation
Transwestern Pipeline Company

APRIL 23, AND OCTOBER 23

Cities Service Gas Company
Commercial Pipeline Company, Inc.

MAY 1, AND NOVEMBER 1

Kentucky-West Virginia Gas Company
McCulloch Interstate Gas Company
Western Gas Interstate Company
Michigan Wisconsin Pipe Line Company
Montana-Dakota Utilities Company
Valley Gas Transmission, Inc.
Great Lakes Gas Transmission Company

OCTOBER 1

Colorado Interstate Gas company
Northern Natural Gas Company (Peoples Division)

NOVEMBER 1

Inter-City Minnesota Pipelines Ltd., Inc.

JUNE 1, AND DECEMBER 1

Louisiana-Nevada Transit Company
Mountain Fuel Resources, Inc.
South Texas Natural Gas Gathering Company
Western Transmission Corporation
Texas Gas Pipe Line Corporation

DECEMBER 1

Kansas-Nebraska Natural Gas Company

DECEMBER 27

Northern Natural Gas Company

(*b*) To assure recovery of all purchased gas costs, the Commission has prescribed deferred purchased gas cost accounts. For Class A and B natural gas companies, the deferred account is "Account 191, Unrecovered purchased gas costs," 18 CFR Part 201, Balance Sheet Accounts, 191 and is used in conjunction with "Account 805.1, Purchased gas cost adjustments," 18 CFR Part 201, Balance Sheet Accounts, 805.1. For Class C and D natural gas companies, the deferred account is "Account 191, Unrecovered purchased gas costs," 18 CFR Part 204, Balance Sheet Accounts, 191 and is used in conjunction with "Account 731.1, purchased gas cost Adjustments," 18 CFR Part 201, Balance Sheet Accounts, 731.1. Pipelines using deferred accounting procedures shall be subject to the provisions of these accounts. In order to qualify for carrying charges, the company is required to adopt the principles of interperiod income tax allocation in connection with the balances recorded in the unrecovered purchased gas cost account.

(*c*) Carrying charges shall be computed based on the ending balances in Account 191, exclusive of accumulated interest each month. Interest will not be compounded. The rate for computation of carrying charges shall be the current rate of interest on pipeline refunds established by the Commission. Carrying charges shall be debited to Account 191 if the ending balance in Account 191 for the month is positive and shall be credited to Account 191 if the ending balance is negative. The carrying charges shall be computed monthly on the net balances in Account No. 191 and the related amounts in Account Nos. 283 or 190, as appropriate, as of the end of the immediately preceding month.

(*d*) After the initial 6-month period following the effectiveness of the PGA clause and after the company has chosen to maintain an unrecovered purchase gas cost account (Account No. 191) the company shall adjust its rate(s), either positively or negatively, to include a surcharge to recover or return the balance which has accumulated in the unrecovered purchase gas cost account (Account No. 191) in the preceding 6-month period. This procedure will be followed in each succeeding 6-month period.

* * * * *

(viii) Pipelines must file tariff sheets pursuant to this part to conform their existing PGA clauses on or before December 1, 1978, which shall become effective as of January 1, 1979. After January 1, 1979, a pipeline shall not be permitted to track changes in purchased gas costs under a PGA clause unless the PGA clause in effect at that time conforms to the rule promulgated in Order No. 13, as modified by Order No. 13-A.I40[FR Doc. 78-33675 Filed 11-30-78; 8:45 am]

[¶ 30,026]

43 F. R. 56448 (December 1, 1978)

[DOCKET NO. RM79-3]

SUBCHAPTER A - GENERAL RULES

PART 2 - GENERAL POLICY AND INTERPRETATIONS

SUBCHAPTER E - REGULATIONS UNDER THE NATURAL GAS ACT

PART 157 - APPLICATIONS FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND ORDERS PERMITTING AND APPROVING ABANDONMENT UNDER SECTION 7 OF THE NATURAL GAS ACT

SUBCHAPTER H - REGULATION OF NATURAL GAS SALES UNDER THE NATURAL GAS POLICY ACT OF 1978

PART 270 - RULES GENERALLY APPLICABLE TO REGULATED SALES OF NATURAL GAS

PART 271 -- CEILING PRICES

PART 273 - COLLECTION AUTHORITY; REFUNDS

PART 274 - DETERMINATIONS BY JURISDICTIONAL AGENCIES

PART 275 - COMMISSION DETERMINATIONS AND COMMISSION REVIEW OF JURISDICTIONAL AGENCY DETERMINATIONS

PART 276 - REPORTS

SUBCHAPTER I - OTHER REGULATIONS UNDER THE NATURAL GAS POLICY ACT OF 1978

PART 284 - CERTAIN SALES AND TRANSPORTATION OF NATURAL GAS

INTERIM REGULATIONS IMPLEMENTING THE NATURAL GAS POLICY ACT OF 1978

AGENCY : Federal Energy Regulatory Commission.

ACTION : Interim Regulations.

SUMMARY: The Natural Gas Policy Act of 1978 (NGPA), enacted November 9, 1978, takes effect with respect to certain first sales of natural gas delivered on or after December 1, 1978. The new statutory provisions relating to pricing of natural gas and other issues must, therefore, be implemented by regulation by that date. These regulations implement certain provisions of the NGPA, and are issued as interim regulations.

PUBLIC HEARINGS: Dates and locations to be announced.

DATE : Written comments by January 31, 1979, except as otherwise noted.

EFFECTIVE DATE: December 1, 1978

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N. E., Washington, D. C. 20426 (Reference Docket No. RM79-3)

FOR FURTHER INFORMATION CONTACT:

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I. INTRODUCTION

On November 9, 1978, the Natural Gas Policy Act of 1978 (NGPA) was signed into law. By passage of the NGPA, Congress has mandated a new legislative framework for the regulation of most facets of the natural gas industry. The new law affects sales, transmission and distribution of natural gas. The previously controlling federal regulatory statute, the Natural Gas Act (NGA) has in many respects been limited, replaced or superseded by the NGPA, although it continues to be of significance with respect to gas previously dedicated to interstate commerce.

A primary effect of the NGPA is the substitution of a series of specific statutory maximum price levels applicable to discrete types of "first sales" of natural gas for the previously established system of price regulation of interstate sales of natural gas which had been grounded in a cost-based methodology. An important distinction between producer regulation under the NGA and the NGPA is the expansion of the Federal Energy Regulatory Commission's (Commission) jurisdictional scope to encompass not only sales made in interstate commerce but in intrastate commerce as well. Under the NGPA, all first sales of natural gas are controlled by the maximum statutory ceiling rates and as a result, it is unlawful for any person to sell natural gas at a price in excess of the statutory maximum regardless of whether the sale occurs in the inter- or intrastate market.

The Commission wishes to call specific attention to the provisions of section 101(b)(9) of the NGPA. The Congress, by that provision, emphasizes and makes clear that the maximum lawful prices under the NGPA are ceiling prices and do not supersede or nullify the effectiveness of any contractual agreement to pay a lower price. Therefore, the Commission cautions producers not to assume entitlement to any NGPA ceiling price which is higher than their contract prices.

The Commission is directed to administer essentially all of the NGPA and is authorized to perform any and all acts and to prescribe and issue such rules and orders as it finds necessary or appropriate to carry out its functions under the NGPA. On November 13, 1978, the Commission proposed interim regulations as the first step in implementing the NGPA. These interim regulations, contained in this notice, mark the second step in carrying out the basic responsibilities for implementation and administration of the Act and provide a mechanism for transition from the NGA regulating regime to the NGPA scheme.

The NGPA is divided into six titles:

- I. Pricing
  - A. Price Controls Applicable to Sales of Natural Gas
  - B. Decontrol of Certain Natural Gas Prices
- II. Incremental Pricing
- III. Additional Authorities and Requirements
  - A. Emergency Authorities
  - B. Other Authorities and Requirements
- IV. Natural Gas Curtailment Policies
- V. Administration, Enforcement, and Review
- VI. Coordination with the Natural Gas Act, Effect on State Laws

The interim regulations prescribed here do not implement all titles under the NGPA. Rather, the regulations propose to deal with those areas demanding the most expeditious treatment.

This first group of regulations is designed to set in motion the new scheme for pricing of first sales of natural gas and to provide mechanisms for implementation of provisions of the NGPA covering certain arrangements for transportation of natural gas. However, before setting out in detail a full description of the specific regulations proposed, a summary of the most salient features of the NGPA, the effect on regulation under the NGA, and a capsule description of the implementing regulations and corollary modifications of regulations under the NGA, may be useful.

THE LEGISLATIVE SCHEME OF THE NGPA

The nature and scope of Commission regulation of producer sales under the NGPA has been substantially transformed from utility-type regulation of a limited market to what is essentially price regulation of an entire national market. Under the scheme set up by the NGPA, there exist two major categories of first sales: those requiring a prior determination of eligibility to be made by a jurisdictional federal or state agency (within the meaning of the NGPA) before collection of the maximum lawful price and those not explicitly requiring such a determination. A decision as to whether a first sale falls into a category requiring a determination is fundamental. A decision to seek a determination triggers quite different regulatory consequences than a decision not to seek a determination.

Although under certain provisions the Commission may be called upon to return to the cost-based, just and reasonable methodology within the meaning of the NGA in establishing rates in excess of the NGPA ceiling prices, the basic administration of the pricing provisions of the NGPA will be undertaken from an entirely different perspective. The Commission will no longer inquire into producer costs or set permissible rates of return for producers. Instead, the Commission's focus will center on whether geological information, production history, field records, prior contractual relationships and information of a similar nature support the categorization for pricing purposes claimed by producers.

Another crucial factor in anticipating what regulatory treatment will be accorded producer sales of natural gas is whether gas is "committed or dedicated" for purposes of NGA regulation. The limitations on NGA regulation as a result of enactment of the NGPA will be addressed in another section of this preamble. However, the distinction between gas which is deemed to be subject to continuing regulation under the NGA and gas which falls solely within the NGPA regulatory format is significant and affects both pricing and nonpricing regulation of producer matters.

For categories of gas requiring a prior determination by a federal or state agency, the Commission's function is more in the nature of an appellate body, reviewing, on a substantial evidence basis, the factual determinations of the appropriate jurisdictional agency with the right of disapproval in the event the initial determination is not adequately substantiated. The Commission rules reflect this role and prescribe the basic and minimum factual foundation necessary to meet its review responsibilities without directly interposing the Commission into the procedural functioning of the jurisdictional agency. The review process of initial determinations begins when notice is received of a jurisdictional agency's determination with the appropriate supporting material specified in Part 274 of the proposed regulations. In the absence of a reversal, the determination of the jurisdictional agency becomes final and no longer subject to review unless based on any untrue statement of material fact or upon any omission of material fact which omission was misleading.

Categories of first sales explicitly requiring that a determination as to qualification to collect the maximum lawful price be made by either a jurisdictional federal or state agency are:

- section 102 which sets a maximum lawful price for first sales of new natural gas (gas produced from a new lease on the Outer Continental Shelf (OCS) or certain new onshore wells) and gas produced from any old OCS lease which was from a reservoir discovered after July 27, 1976;
- Section 103 which sets a maximum price for first sales of new onshore production wells;
- Section 107 which sets a maximum lawful price for first sales of high-cost natural gas including gas produced from geopressurized brine, coal seams, Devonian shale or gas produced under other conditions the FERC determines to present "extraordinary" risks or costs; and
- Section 108 which sets the maximum lawful price for first sales of stripper well natural gas.

An essential element in the regulatory system established with respect to categories requiring a prior determination is the provision for interim collection procedures by producers awaiting a final determination or the outcome of a review of such determination. The Commission has a concomitant power to require refunds from the producer if the gas eventually qualifies for a lower price. Section 503(e) sets out this collection and refunding procedure.

Part 273 of the regulations states the prerequisites for interim collection. First, the Commission has established a "transitional rule" to permit the collection by producers of the section 109 price if a producer files for a determination by March 1, 1979. Additional rules are established for interim collection pending and following a state or federal agency determination.

Those first sales of natural gas not requiring a prior determination to be made by a jurisdictional federal or state agency are tied to previously existing contractually set prices or price levels established by the Federal Power Commission or this Commission. First sales not requiring a prior determination under the NGPA are:

- section 104 which incorporates by reference the just and reasonable rates established under the NGA for first sales of gas committed or dedicated to interstate commerce on the day before the date of enactment of the NGPA;
- section 105 which establishes maximum lawful prices for first sales under existing contracts of natural gas not previously committed or dedicated to interstate commerce;
- section 106 which establishes maximum lawful prices for first sales under interstate and intrastate rollover contracts; and
- section 109 which establishes the maximum lawful price for first sales of natural gas from the Prudhoe Bay in Alaska and categories of gas not otherwise covered by other sections of the NGPA.

The Commission has general administrative and enforcement authority under the NGPA and the NGA to order refunds in cases where the maximum lawful price level has been improperly exceeded.

EFFECT OF THE NGPA UPON CONTINUED NGA REGULATION

Natural gas which remains committed or dedicated to interstate commerce on the day before the date of enactment of the NGPA, or which is not specifically exempted from the jurisdictional consequences of commitment or dedication by the NGPA, remains subject to all the non-price regulatory requirements of the NGA. An important aspect of continued NGA regulation is the requirement that a producer file an abandonment application with the FERC pursuant to section 7(b) of the NGA before terminating service to the interstate market or before abandonment of facilities used to render interstate service. Additionally, although price regulation of first sales by producers of gas committed or dedicated is now governed by the NGPA, sections 104 and 106(a) are grounded in previously established rates under the NGA. As a result, producers wishing to establish their right to collect under these sections will be required to make a filing under their rate schedules under the NGA. The Commission has amended its previously existing filing requirements to provide new procedures governing these rate increase filings.

If gas is not committed or dedicated to interstate commerce as defined in section 2(18) or is exempted from the jurisdiction of the NGA under section 601(a)(1)(B) as high cost natural gas, new natural gas, or natural gas produced from any new onshore production well, the prior framework of utility-type regulation under the NGA no longer applies.

If natural gas sales are freed from the requirements of the NGA, several adjuncts to NGA regulation are obviated. First, there is no longer any necessity for a producer to seek certification of the sale as serving the public convenience and necessity. The replacement for this requirement under the NGPA is limited to the prior determination mechanism, where applicable, and the pricing limits established in the NGPA. New sales of such gas in interstate commerce no longer require certification as a prerequisite to commencement of deliveries. Nor does the requirement for abandonment authorization before termination of deliveries of natural gas exist with respect to natural gas no longer subject to NGA regulation. In the case of first sales of natural gas not previously committed or dedicated to interstate commerce or exempted from NGA regulation, tariff filings and rate increase applications are dispensed with. (Of course, specific requirements for filing to establish the right to collect the maximum lawful price levels exist under the regulations and annual reporting will be required under the NGPA in many instances. However, the nature of these filings, which are in many cases one-time notification type filings is quite different from the rate filings previously required under the NGA.)

For natural gas which on the date of enactment was committed or dedicated but which is exempted from the NGA under section 601(a)(1) of the NGPA, there are substitute mechanisms for NGA section 7(b) abandonment authorization. These substitute provisions, intended to provide a degree of certainty to purchasers dependent upon a predictable natural gas supply, are found in section 315 of the NGPA. The Commission has not attempted to implement these sections in the initial implementing regulations. It is our intent to do so in the near future. That section gives the Commission dual authority to establish by rule or order the minimum duration of any contract (other than an existing contract) for the purchase of natural gas and to require by rule the right of first refusal with respect to any gas committed or dedicated to interstate commerce before the date of enactment if such gas is high cost gas, new natural gas or natural gas produced from any new, onshore production well.

Indirectly, NGA regulation is affected by the operation of section 601(b) and (c) of the NGPA. Section 601(b) provides that any amount paid in any first sale of natural gas shall be deemed to be just and reasonable if such amount does not exceed the maximum lawful prices established by the NGPA or if there is no maximum lawful price applicable by reason of elimination of price controls. Section 601(c), the guaranteed passthrough provision, states that the Commission may not deny, or condition, the grant of any certificate under section 7 of the NGA based upon the amount paid in any sale of natural gas if the amount paid meets the standards of section 601(b) and is, therefore, by statutory fiat, just and reasonable. Additionally, the Commission may only deny the recovery by any interstate pipeline of any amount paid with respect to the purchase of natural gas under section 601(b) to the extent the Commission determines that the amount paid was excessive due to fraud, abuse, or similar grounds.

Finally, included in the implementing regulations are provisions covering certain transportation arrangements by both interstate and intrastate pipelines. Provision is made for intrastate pipeline sales and for the assignment of natural gas excess to their requirements. Also, the Commission has revised its regulations previously applicable to emergency transactions and revised the procedure and the standards for emergency sales of natural gas for this winter's heating season.

GENERAL OUTLINE OF IMPLEMENTING REGULATIONS

The interim regulations add two new subchapters to the Commission's regulations in Chapter 1 of Title 18. New Subchapter H (Parts 270 through 276) contains the new producer regulations under the NGPA. Part 270 sets forth general rules applicable to the entire subchapter. Maximum lawful prices under NGPA sections 102 through 109 are implemented in Part 271. Part 273 provides for interim collections and refunds, while determinations of eligibility by state and federal agencies and Commission review of those determinations are provided for under Parts 274 and 275. Finally, Part 276 covers reports.

New Subchapter I will cover regulations under the NGPA other than those relating to producer regulation. The interim regulation prescribed today includes only Part 284, which implements the Commission's authority under sections 311(a) (relating to certain pipeline transportation of natural gas) and 312 (relating to assignment of intrastate pipeline's contractual right to receive surplus natural gas). Regulations relating to other authorities of the Commission will be added later under Subchapter I.

II. SUMMARY OF PROPOSED REGULATIONS

PART 270

Part 270 prescribes rules and definitions that apply to Subchapter H. Subpart A contains the general rules and definitions, and Subpart B contains special rules which relate to sales made under particular conditions.

The general rules of § 270.101 relate to the application of the maximum lawful price provisions of the NGPA. This section makes it unlawful for any person to sell natural gas at a first sale price which is greater than the highest maximum lawful price permitted under Part 271. Thus, if more than one maximum lawful price is applicable to a first sale, the "highest" maximum lawful price may be obtained.

This section also describes the categories of natural gas for which prior determinations by jurisdictional agencies must be made in order to establish the maximum lawful price. In addition, this section reflects the statutory rule that the pricing provisions of Part 271 do not supersede or nullify contract provisions which establish prices below the applicable maximum lawful price. It also provides that collection of a first sale price under Subchapter H is subject to any refund obligation as may be applicable. The refund provision has been modified from the proposal to recognize the fact that refund obligations may arise as a result of provisions other than those in Part 273.

Comments on the proposed regulations requested additions to the general rules. One comment suggested a rule to protect confidential data submitted pursuant to these new regulations. The Commission, in response to this concern, has added a rule to Subpart B of Part 275 concerning the confidentiality of materials submitted to it as part of a determination by a jurisdictional agency.

Section 270.102 contains definitions. Paragraph (a) provides that unless further defined, terms defined in the NGPA have the same meaning for purposes of these regulations as they do under the NGPA.

The definitions provided under paragraph (b) include basic terms used throughout the regulations and particular terms, such as "production in commercial quantities," "crude oil," "surface location," "intrastate contract," "successor to an intrastate contract," and "intrastate rollover contract," used in more than one subpart. Two of these definitions differ from those which were first proposed: that for "Btu," and that for "production in commercial quantities."

The definition of "Btu," found in clause (2) of paragraph (b), has been amended to conform it to § 270.204. This was done in response to those comments which pointed out a discrepancy between these two sections.

In addition to several minor clarifying changes, the term "production in commercial quantities" has been amended in two major respects. First, in response to those comments which noted the Commission's omission of any reference to the rebuttable presumption in section 102(c)(3) of the NGPA, a citation to a new § 271.204(e), which embodies that presumption, has been included. Also in response to comments, the definition has been modified to make clear that the information in clauses (A) to (E) inclusive, of § 270.102(b)(4)(iii), may be considered evidence of production for beneficial economic use. However, the Commission wishes to point out that these enumerated clauses are not conclusive as to the matter; evidence to show the contrary may be presented by an applicant for a determination.

Several comments proposed that this section be expanded to include certain other terms, including "local distribution company," "intrastate sales," and "first sale." The Commission has determined that definition of these terms is not required at this time.

The table of names and addresses of the jurisdictional agencies has been moved from Part 270 to the new Subpart E of Part 274. In addition, several corrections have been made in the table.

The special rules of Subpart B apply to first sales of natural gas subject to differing maximum lawful prices, resales covered by first sale pricing regulations, sales of natural gas attributable to pipeline or distributor production, and the measurement of Btu content of natural gas.

Section 270.201 provides that the maximum lawful price for a first sale of natural gas produced from wells, properties, or reservoirs which have different applicable maximum lawful prices will be the weighted average of the maximum lawful prices applicable to each well, property or reservoir. The weighted average will be based upon the volumes of gas contributed by each such well, property or reservoir.

Section 270.202 applies to "resellers." The section provides that one who purchases natural gas at a first sale and subsequently resells the gas in a transaction which is also a first sale may collect a maximum lawful price which is the higher of either: (1) the maximum lawful price which would apply to such a sale under Part 271 if it were not a resale; or (2) the maximum lawful price which was applicable to the transaction in which the reseller purchased the natural gas. A rule similar to § 270.201 applies to any sale by a reseller of volumes purchased subject to different maximum lawful prices.

Paragraph (c) of the rule contains two provisions applicable to allowances under Subpart K of Part 271. First, the reseller may collect the applicable maximum lawful price on his sale plus any allowances permitted by the Commission under the provisions of Subpart K of Part 271. Second, if the reseller's maximum lawful price is determined under § 270.202(a)(2) by reference to the maximum lawful price of the person selling to him, the reseller may pass through any Subpart K allowances which the person selling to him collected. In addition, under § 270.202(d), a reseller may apply to the Commission for adjustment relief pursuant to section 502(c) of the NGPA, to the extent the application of the reseller provisions results in hardship, inequity, or an unfair distribution of burdens.

Section 270.202 also spells out the manner in which the interim collection rules apply to resellers and sets out rules respecting reporting and record retention. With regard to reporting requirements, it should be pointed out that resellers must make reports of their first sales under Part 276 in the same manner as other first sellers.

Significant modifications in the reseller rule as proposed were made in response to comments received by the Commission, in particular in its treatment of allowances under Subpart K of Part 271. The comments pointed to the possibility of a reseller's being "squeezed" between applicable prices at which he purchased and those at which he could sell. These comments suggested that the Commission explicitly provide for allowances such as the current gathering allowances permitted to interstate production and those afforded producers under Subpart K of Part 271. In addition, suggestions were made that the regulation provide for some form of margin protection to resellers. While the Commission declines to go so far as to guarantee existing margins, we believe that, as presently constructed, this regulation meets the concerns expressed by those who commented upon the proposed rule. The result, especially with the changes made respecting reseller allowances and passthrough of allowances, and with the provision for adjustments under section 502(c) of the NGPA, should provide for equitable treatment of resellers. It should be noted that changes in Subpart K of Part 271 have also been made.

Section 270.203 relates to pipeline and distributor production. Section 2(21)(B) of the NGPA provides that a sale of natural gas by a pipeline or distributor (or an affiliate thereof) is not a first sale unless the sale is "attributable to volumes of natural gas produced" by such pipeline or distributor (or an affiliate thereof). Section 270.203 describes the circumstances under which a sale of natural gas will be considered to be a first sale of natural gas attributable to volumes produced by a pipeline or distributor. To the extent a sale is comprised exclusively of production volumes from identifiable wells, properties, or reservoirs which are owned by the pipeline or distribution company or affiliate thereof making the sale, then it is attributable to volumes of natural gas produced by that pipeline or distributor.

For example, if a pipeline sells to a particular customer production volumes from a well which it owns, the volumes are commingled with system supply, and equivalent volumes are withdrawn for delivery to that customer, then the transaction would be a sale comprised of production volumes from a particular well, and thus a first sale.

In order to prevent circumvention of this rule, a provision is made pursuant to the Commission's authority under section 2(21)(A)(v) of the NGPA, that mixed-volume sales comprised of both production volumes from identifiable wells, properties, or reservoirs owned by the pipeline or distributor/seller and of other production volumes will be considered as a first sale, unless one of the two exclusions under the rule applies. The first exclusion provides that if the rate at which such natural gas is sold by the pipeline or distributor is regulated under the NGA or subject to regulation by a state agency under state law, then the sale will not be considered to be a first sale by reason of the "circumvention rule." (To qualify for the state regulation exemption, the sale must be subject to regulation by a state agency empowered by state statute to establish, modify or set aside the rate for the sale.) The second exclusion provides that the sale will not be considered as a first sale if, on application to the Commission, a determination has been made not to so treat the sale.

The effect of § 270.203 on sales made by an interstate pipeline of volumes of natural gas produced by it, is to continue resale rate regulation under the provisions of the NGA.

While some comments were received calling the Commission's attention to intracorporate transfers, the Commission will not specifically deal with this question without receiving further comment. Unless the Commission otherwise provides, intracorporate transactions by interstate pipelines will continue to receive the treatment presently accorded them under the NGA.

The Commission should note at this point the relationship of section 602(a) of the NGPA to the attribution and circumvention rules set out in § 270.203. Section 602(a) states that nothing in the NGPA limits the authority of a state to establish or enforce a maximum lawful price for the first sale of natural gas produced in the state, provided the price set does not exceed any appropriate maximum lawful price under Title I of the NGPA.

Comments were received that indicate certain states have authorized their regulatory body to set or impute a price on the basis of fair value or reasonable market price for the sale or transfer to an intrastate pipeline by its producing affiliate or production department. These state-set values may be below the applicable NGPA ceiling price.

Nothing in § 270.203 or the NGPA precludes a state agency from establishing a ceiling price for a sale of gas by an intrastate pipeline affiliate to an intrastate pipeline at a rate which is lower than the NGPA ceiling price. Likewise, a state agency may impute a price for an intracorporate transaction involving intrastate pipeline production which is lower than the NGPA ceiling price. Some comments received by the Commission interpreted the proposal as one which, contrary to the NGPA, worked to exclude all sales of pipeline-produced natural gas from the provisions of the NGPA. Others interpreted the proposed rule as one which would continue, where applicable, cost-of-service regulation subject to the maximum lawful pricing provisions of the NGPA. Still others, notably intrastate producer pipelines, pointed out cases where state regulation does not take the form of cost-of-service or average cost regulation.

We disagree with those comments that concluded that the Commission is without authority to determine the extent to which sales by pipelines and distribution companies are "attributable" to production by these entities, or their affiliates. Under a broad reading of this section, arguably all sales of natural gas by pipelines and distribution companies would be "first sales" where any volume of natural gas was produced by that pipeline, distribution company or an affiliate. Under such a reading, a substantial portion of retail sales by pipelines and distribution companies would be subject to the provisions of the NGPA. Moreover under such a broad reading of the "first sale" definition, it could be asserted that the provisions of the NGA would not apply to jurisdictional sales by interstate pipelines by reason of section 601 of the NGPA.

Applying the provisions of Title I of the NGPA, particularly section 104, to "first sales" by interstate pipelines under such a broad reading would entail a major restructuring of pipeline regulation under the NGA. Retail sales by intrastate pipelines and distribution companies, which are traditionally regulated by the states, would also be subject to the provisions of Title I of the NGPA and the Commission's authority. Such incongruous results were clearly not intended by the legislative draftsmen.

For these reasons we have concluded that sales by pipelines and distribution companies should only be considered to be "attributable" to production by pipeline distributors where the sale is of production from identifiable wells, properties or reservoirs owned by such pipelines or distributors (or affiliates thereof) to an identifiable purchaser. In order to prevent circumvention of this rule by pipelines or distributors who sell volumes of production by others together with volumes produced by them, the Commission has found it necessary to exercise its authority under section 2(21)(A)(v) of the NGPA, to impose first sale price regulation on these "mixed" sales where the price is not otherwise subject to regulation or where the Commission affirmatively finds that first sale regulation is unnecessary.

Section 270.205 incorporates discussion at page 83 of the Statement of Managers which relates to the effect of establishment of ceiling prices under the NGPA on indefinite price escalator clauses in existing contracts. As discussed there, the mere establishment of NGPA ceiling prices will not trigger these clauses. The special rule is consistent with that discussion which is equally applicable to existing intrastate and interstate contracts. The phrase "indefinite price escalator clause" is defined for purposes of this special rule bv reference to the definition in Section 105(b)(3)(B). Good cause exists to incorporate this special rule in the interim regulations given the uncertainty that would result absent a provision which provides guidance to the parties to those contracts.

PART 271 - SUBPART A

Subpart A of Part 271 sets out, in summary tables, the pricing provisions applicable to certain categories of first sales of natural gas delivered in the months of December 1978 and January 1979. It also provides the method and the inflation adjustment factors to be used for calculating maximum lawful prices for those categories of natural gas for which prices cannot be derived from the summary tables. These latter categories are ones for which maximum lawful prices must be calculated by the seller.

Section 271.102 sets out the methodology by which certain maximum lawful prices are to be calculated. The procedure involves adjustment for inflation and requires only simple multiplication. The price for a given month is calculated by multiplying (1) the price which was allowed for the sale of natural gas delivered in the preceding month, by (2) a single adjustment factor which is published by the Commission. The adjustment factor, referred to as the "monthly equivalent of the annual inflation adjustment factor" in the NGPA, and "inflation adjustment" in the interim regulation, is computed by the Commission under the method of calculation prescribed by section 101(a) and (b) of the NGPA. The inflation adjustment for each month after April 1, 1977, appears in Table III in § 271.102. This adjustment will be published by the Commission at least 5 days before the beginning of any month for which the factor will apply.

The first price from which all maximum lawful prices under § 271.102 are to be calculated is referred to as a "base price." This price varies according to the category of natural gas for which a calculation is to be made. Once this price is known the calculation can proceed, month-to-month, until the applicable monthly maximum lawful price is determined.

By way of example, assume that a calculation is to be made to determine the December 1978, maximum lawful price for natural gas subject to § 271.402(d)(1) for which a just and reasonable rate of $1.00 was in effect on April 20, 1977. First the "base month" and "base price" must be determined. These are determined under §271.102(d) to be April 1977, and $1.00 respectively. Second, a calculation for May 1978, is made. This is done by multiplying $1.00 by 1.00636, the inflation adjustment for May 1977, as presented in the table accompanying § 271.102(c). The result, rounded to the nearest mill, is $1.006. Next, the process is repeated for June 1978 by multiplying the $1.006

figure by 1.00636, the inflation adjustment for June. The product, again rounded to the nearest mill, is $1.012. This figure is then multiplied by the inflation adjustment for July 1977 (1.00431) and so on through the monthly iterations. The result should be a price of $1.115 for the month of November 1978. At this point, the maximum lawful price applicable for deliveries made in December 1978, can be determined. This is done by multiplying the November figure of $1.115 by 1.00581, the factor which applies for December. The result is a maximum lawful price of $1.121 for deliveries made during December 1978.

This example is chosen to illustrate the calculation which § 271.402 will require of some sellers. Sellers subject to either the § 271.502 or § 271.602 pricing provisions will be entitled to prices based on the contract price per MMBtu on November 9, 1978, or in the case of rollover contracts, the month in which the rollover occurs. In either event, only a single multiplication need be made to determine the next month's maximum lawful price.

PART 271 - SUBPART B

Subpart B of Part 271, which implements section 102 of the NGPA, establishes a maximum lawful price for "new natural gas" and for "natural gas produced from a new OCS reservoir on an old OCS lease." These terms are defined by reference to the NGPA.

Section 271.204(a) is a special rule for vertical measurement of the 1,000 foot distance between completion locations necessary for certain determinations under this subpart. The rule also clarifies the measurement methodology for completions made by perforation and for "open-hole" completions.

Section 271.204 also provides special rules regarding the statutory terms "capable of producing in paying quantities," "commercially producible," "suitable facilities," and "production in commercial quantities."

Comments suggested the term "reservoir" be defined in § 271.203. Section 270.102(a) of the regulations provides that the NGPA statutory definitions are incorporated by reference in the regulations. The term reservoir is defined in section 2(6) of the NGPA.

Comments suggested several modifications to the special rules in § 271.204. Specifically, comments directed toward § 271.204(a) suggested an alternate method of measuring vertical depth, viz. from the lowest perforation point in the marker well to the highest perforation point in the new well completion location. Further comments suggested that measurement of open-hole completions should be from the total depth of the marker well to the highest point of the new well reservoir. The Commission has considered this suggestion and has decided for reasons of ease of measurement and consistency, not to change the special rule. However, in response to some comments, the rule regarding vertical measurements has been changed to make clear that for open-hole completions, measurements are from the highest elevation point of the reservoir "within the well bore."

Several comments sought modification of the special rule regarding "commercially producible" arguing that section 102(d)(2)(B)(ii) of the NGPA requires a determination based upon the producing characteristics of the reservoir. The Commission has found no basis for concluding that the term "commercially producible" has a meaning different from "production in commercial quantities." The latter term is defined in § 270.102(b)(4) of the regulations.

Other comments suggested that the language in § 271.204(d), which provides that suitable facilities were in existence if such facilities were "substantially installed and additional facilities necessary for such production and delivery were readily available," should be deleted or modified. It is the Commission's position that the statutory term "suitable facilities" includes facilities which were installed or substantially installed, if any additional facilities necessary for production and delivery were readily available. However, the section has been modified, in response to comments, to make clear that unless suitable facilities were actually in place, such facilities will not be considered to be "readily available" unless the additional facilities could have been installed in time to allow production and delivery to commence prior to April 20, 1977.

Finally, in response to other comments, § 271.204(d) has been modified to reflect the statutory provisions that facilities installed solely for purposes of sales under section 6 of the Emergency Natural Gas Act of 1977, or for the purposes of 60-day emergency sales are not "suitable facilities" within the meaning of section 102 of the Act.

PART 271 - SUBPART C

Subpart C of Part 271 implements section 103 of the NGPA and establishes a maximum lawful price for first sales of natural gas from new, onshore production wells. Section 271.303 defines a "new, onshore production well" in accordance with the statutory definition in section 103(c), as one spudded on or after February 19, 1977, which complies with applicable well-spacing requirements, and is outside an existing proration unit. Wells which do not comply with applicable well-spacing requirements or are drilled within an existing proration unit do not qualify for the new, onshore production well price unless the requirements of the special rule set out in § 271.304 are met. Section 271.304 makes clear that if a jurisdictional agency grants a waiver of well-spacing requirements prior to commencement of surface drilling, the new well is deemed to satisfy applicable well-spacing requirements.

The special rule in § 271.305 is divided into two parts. The first part, paragraph (b) of § 271.305, provides that for wells spudded after December 31, 1978, the requirements of section 103(c)(3) of the NGPA can only be satisfied if the jurisdictional agency finds that the well is necessary to effectively and efficiently drain a portion of the reservoir covered by the proration unit, which portion of the reservoir cannot be effectively and efficiently drained by any existing well within the proration unit. Such a finding must involve a redefinition or alteration of the proration unit, or an exception to otherwise applicable well-spacing requirements.

Paragraph (c) of the rule recognizes that some wells drilled between February 19, 1977, and January 1, 1979, may qualify for the price established in section 103. The rule permits such wells to qualify if the agency which authorized the drilling of the new well explicitly or implicitly made the finding, prior to commencement of the drilling of the well, that the new well was necessary to effectively and efficiently drain a portion of the reservoir covered by the proration unit, which portion of the reservoir could not be effectively and efficiently drained by any existing well within the proration unit. Similar treatment is accorded certain wells for which drilling permits are issued prior to January 1, 1979.

Numerous comments requested that the applicability of the special rule in § 271.305 be clarified. The special rule only applies to a second well drilled in an existing proration unit. If there is no proration unit in existence and applicable to the reservoir, or if there is no well drilled in the existing proration unit to the reservoir, the special rule does not apply. Paragraph (a) of the special rule regarding the applicability of the rule has been revised to clarify this point.

Several comments requested a transition period during which jurisdictional agencies may develop procedures necessary to make the explicit finding required by § 271.305(b). The Commission recognizes the need to permit a sufficient transition period. Paragraph (b) now applies to "wells spudded after December 31, 1978, and paragraph (c) now applies to "wells spudded on or after February 19, 1977, and before January 1, 1978."

Many comments questioned whether the finding that the new well is necessary to effectively and efficiently drain a portion of the reservoir covered by the proration unit which cannot be effectively and efficiently drained by any existing well within the proration unit must be made prior to the commencement of drilling. Comments stated that this requirement would cause drilling delays or make it impossible to obtain a new, onshore production well determination for wells drilled prior to the date of enactment. The Commission believes that the statute requires that the necessary finding be made prior to the commencement of drilling. Consequently, this aspect of the special rule in § 271.305 remains unchanged.

PART 271 - SUBPART D

Subpart D of Part 271 implements sections 104 and 106(a) of the NGPA. These sections prescribe the maximum lawful price for the first sale of natural gas which was committed or dedicated to interstate commerce on November 8, 1978, and for which a just and reasonable rate under the NGA was in effect. Under section 104, the maximum lawful price is the just and reasonable rate for each vintage of gas established by the Commission as of April 20, 1977, as adjusted monthly for inflation from that date forward. Just and reasonable rates established by the Commission after April 20, 1977, constitute the ceiling rates under section 104 and are not generally adjusted for inflation. Section 106(a) prescribes the maximum lawful price for rollover contracts executed after November 9, 1978.

The interim regulations set forth the maximum lawful price applicable to each vintage of gas and define the various vintages of gas established by the Commission's national or area rate opinions. Rules for calculating the maximum lawful price applicable to natural gas for which a nonvintage just and reasonable rate was not previously established under special relief and optional procedures are also included in this subpart.

Section 271.402(a) of Subpart D includes a table of maximum lawful prices for each vintage of previously committed or dedicated natural gas. Transition from the Natural Gas Act prices to the NGPA prices affects two of the prices included therein differently from other categories. First, the price established in section 106(a) of the NGPA for sales by small producers of rollover contract gas is less than the rate such producers would have received for the same category of gas under the Natural Gas Act. Pursuant to § 157.40(c)(1) of this chapter, small producers were entitled, under the Natural Gas Act, to 130% of the maximum base rate established by the Commission for replacement contracts. Thus, for replacement contracts entered into prior to November 9, 1978, section 104 of the NGPA, which is keyed to the rates previously established by the Commission, prescribes a rate reflecting this 30% differential for sales by small producers. However, for contracts rolling over on or after November 9, 1978, section 106(a) prescribes a rate of 54 cents per MMBtu, as adjusted for inflation from April 20, 1977, for both large and small producers. As a result of this anomaly, a small producer who executed a replacement contract prior to November 9, 1978, would be entitled to a rate of 77.1 cents per MMBtu as of December 1, 1978, whereas a small producer who executed a rollover contract on or after November 9, 1978, would be entitled, under section 106(a), to a rate of 60.3 cents per MMBtu.

In order to prevent a small producer from receiving a rate under the NGPA lower than that to which he would be entitled under the Natural Gas Act, the Commission finds it necessary to invoke our authority under section 106(c) of the NGPA. This section provides that the Commission may prescribe a maximum lawful price higher than would otherwise be applicable under section 106 if such higher rate is determined to be just and reasonable within the meaning of the Natural Gas Act. The Commission finds, pursuant to this section, that the rate previously established by the Commission for small producer replacement contract gas is just and reasonable within the meaning of the Natural Gas Act, and should be made applicable to small producer sales of rollover contract gas. The price so determined is 70.2 cents per MMBtu as of December 1, 1978. This price may be increased, in accordance with Opinion Nos. 770, _et seq_. and Opinion Nos. 742, _et seq_., by an amount not to exceed 1.3 cents per MMBtu per annum commencing on January 1, 1979, and the first day of every year thereafter for the term of the contract dedicating the subject gas for sale in interstate commerce.

We note that this price is still not identical to the 77.1 cents per MMBtu price prescribed in the table for small producer sales of replacement contract gas. The price in the table was determined by adjusting for inflation the April 20, 1977, price of 68.9 cents per MMBtu established by the Commission for replacement contract gas. We invite the submission of data, views and arguments on or before December 15, 1978, regarding the question whether, under the standard set forth in section 106(c), the 70.2 cents per MMBtu rate applicable to small producer rollover contracts should be found not just and reasonable, and the just and reasonable rate should be raised to the 77.1 cents per MMBtu rate as adjusted for inflation in months following December 1978.

One commenting party argues that the Commission has exceeded its authority in raising the small producer rollover contract rate to 70.2 cents per MMBtu. The comment alleged that by not mentioning small producers in section 106(a), Congress intended to eliminate the small producer differential for rollover contract gas. We disagree. The Commission believes the intent of Congress, as expressed in sections 104 and 106(a) of the NGPA, was to key the price of previously committed or dedicated gas to the prices previously determined by the Commission to be just and reasonable under the Natural Gas Act. Accordingly, we believe that the failure of section 106(a) to mention small producers was inadvertent rather than intentional. In any event, the Congress clearly provided the Commission with the authority, under section 106(c), to prescribe a just and reasonable rate for small producers selling rollover contract gas which is higher than that provided in section 106(a).

A second transition problem exists regarding the large producer rate for rollover contracts prescribed in section 106(a). Such rate is determined by applying the inflation adjustment factor to an April 1977 rate of 54 cents per MMBtu in order to arrive at a December 1, 1978, rate of 60.3 cents per MMBtu. However, the large producer rate for replacement contracts was 53 cents as of April 20, 1977, which when adjusted for inflation translates to a rate of 59.3 cents per MMBtu as of December 1, 1978. Again, we note that the only difference between a replacement contract and rollover contract is that the latter is executed on or after November 9, 1978. In view of this disparity in treatment for the same types of sales of natural gas, we invite the submission of data, views and arguments on or before December 15, 1978, regarding the question whether, under the standard set forth in section 104(b)(2), the large producer replacement contract rate of 59.3 cents per MMBtu should be found not just and reasonable, and the just and reasonable rate should be raised to the 60.3 cents per MMBtu rate for large producer rollover contracts.

Under § 271.402(d)(2) of these regulations, any "just and reasonable" rate established by the Commission for a sale of natural gas after April 20, 1977, and prior to November 9, 1978, is the maximum lawful price applicable to such sale if higher than the otherwise applicable price prescribed in § 271.402(a) or (d)(1). As to producer applications under the optional procedure regulation set forth in § 2.75 of this chapter, a "just and reasonable" rate is that rate established by the Commission in its final order on such applications. However, the holder of a certificate issued by the Commission under the optional procedure was required to waive the right to receive the applicable national and area rates and other rights under section 4 of the Natural Gas Act and regulations thereunder, we do not believe that the inflation adjustment should apply to rates established under the optional procedure.

Under § 271.403 of these regulations, we have provided a special rule regarding a carrying charge adjustment for advance payments. In Opinion No. 770-A, the Federal Power Commission recognized that capital generated through the advance payment program was no longer required to bring additional gas supplies to the interstate market. The Commission noted that the rate level set forth in that opinion was designed to achieve the capital formation objective. Accordingly, the Commission found that as to additional advance payments made after the issuance of that opinion, it would be inequitable to require consumers also to pay the carrying charges on these amounts.

The Commission determined that producers who accept advance payments after the date of the opinion should reduce the rate prescribed therein for post-1974 gas which was committed under any further advance payments by the cost of the advances borne by consumers.

Because of these same considerations, we have provided in § 271.403 for the same adjustment in the rates charged by producers for post-1974 gas. Producers subject to this carrying charge rule would be required to reduce their rates by 83 cents per MMBtu for all deliveries made pursuant to the applicable advance payment agreement until the total amounts so deducted equal the amounts collected by the purchasing pipeline from its customers as a result of including the applicable advance payments in their rate base.

Several parties commented that § 271.402(a) should include a reference to the minimum rate of 18 cents per Mcf prescribed by § 2.56b(b) of this chapter. These parties also stated that this 18 cents per Mcf minimum rate be adjusted for inflation as provided for in section 104(b)(1)(A).

We agree that the 18 cents per Mcf minimum rate should be included in the table of rates set forth in § 271.402(a) and should be adjusted for inflation as provided in section 104(b)(1)(A). Accordingly, we have added a new category to the table of rates set forth in § 271.402(a) which is entitled "minimum rate gas." Also, we have added a new subparagraph (9) to § 271.402(c) which defines this term.

Several comments were received regarding the "small producer" definition set forth in § 271.402(c)(9). One comment suggested that the definition be expanded to include a crossreference to § 157.40, the current regulation governing sales made by small producers. Specifically, this comment requested that it be made clear that the small producer rates established under sections 104 and 106(a) should only be applicable to sales from "small producer reserves" as defined in § 157.40. In order to clarify this matter, we have deleted the definition of small producer and, in its place, provided a definition of "small producer sales" which references the requirements of § 157.40 under which such sales may qualify for the small producer rate.

One comment recommended that we amend the definition of small producer to permit the small producer exemption to apply even where the producer is a director of a class A pipeline company and the producer makes no sales to such pipeline company. This prohibition against affiliation with a class A pipeline company was incorporated in the current small producer regulations set forth in § 157.40 as promulgated by Order No. 568. [1] On rehearing of Order No. 568, the issue presented in this comment was raised. Since this issue is more appropriately raised in the context of Order No. 568, we shall address it on rehearing of that order.

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[1] Order Amending and Clarifying Small Producer Regulations, Docket No. RM76-15, issued July 14, 1977.

Finally, a comment was received recommending that small producers be defined by reference to the level of sales in both the inter- and intrastate markets, because the NGPA abolished this distinction between the markets. However, the small producer definition set forth in § 271.402(c)(9) is only applicable to sales of natural gas which was previously committed or dedicated to interstate commerce, and the maximum lawful prices established for such gas are based on the just and reasonable rates previously established by the Commission. Accordingly, the small producer exemption which is provided for under the Commission's current pricing regulations and which is based solely on the level of interstate sales, should be maintained. To include intrastate sales in the exemption rule would mean that certain producers would receive a rate under the NGPA lower than that to which they would be entitled under the Natural Gas Act, a result clearly not intended under sections 104 and 106(a).

One party indicated that the term "replacement contract" as used in § 271.402(c)(4) should be clarified in that it may be confused with the term "successor to an existing contract" under section 2(14) of the NGPA. No further clarification in the regulations need be made because the two terms are distinguishable on their face. First, "successor to an existing contract" means a contract executed on or after November 9, 1978, whereas a "replacement contract" refers only to contracts executed prior to that date. Also, a replacement contract also differs from a "successor to an existing contract" in that it refers only to contracts for the sale of natural gas which was previously subject to an existing contract which expired by its own terms.

PART 271 - SUBPART E

Subpart E of Part 271 implements section 105 of the NGPA by setting forth the procedure for determining the

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maximum lawful price for first sales of natural gas under existing, or successors to existing, intrastate contracts. No prior Commission approval is required in order to collect the maximum lawful prices established in this subpart. Persons making sales under existing intrastate contracts need only file reports as provided in Part 276. "Existing intrastate contracts" are defined in § 270.102(b)(8) to be any intrastate contracts for the first sale of natural gas in existence on November 8, 1978.

Although throughout the proposed regulations the reference is to intrastate contracts, it should be noted that these provisions apply to contracts which govern the sale of natural gas which was not committed or dedicated to interstate commerce on November 8, 1978, (the day before the date of enactment of the NGPA). Included in this category is any gas which was sold in interstate commerce under an emergency sale, a limited term certificate, and certain direct sales for which specific transportation certificates had been issued by the Commission.

Under Subpart E of the proposed regulations, the maximum lawful prices depend upon the relationship that existed on November 9, 1978, between the price under the terms of the existing intrastate contract and the new natural gas price. Under § 271.502(a), if the existing intrastate contract price was less than the new natural gas price, then the maximum lawful price will be, pursuant to section 105(b)(1) of the NGPA, the lower of the new natural gas price of $2.060 per MMBtu or the price under the terms of the existing intrastate contract on November 9, 1978, (as such price may be changed from time to time in accordance with contract terms in effect on November 9, 1978). Under § 271.502(b), if the existing intrastate contract price exceeded the new natural gas price of $2.060 per MMBtu on November 9, 1978, then the maximum lawful price will be the higher of the new natural gas price or the existing intrastate contract price limited to escalation by the monthly equivalent of the annual inflation adjustment factor.

The term "contract price" is defined in § 271.504 to mean the price per MMBtu charged for deliveries of natural gas occurring on a specific date, or the price that would have been charged had deliveries occurred on that date.

Comments were received from various parties concerning our use of the phrase "contract price" in § 271.502(a)(1). They asserted that its use in that paragraph caused confusion as to whether future contractually authorized fixed or indefinite price escalator clauses, including price redetermination provisions, operate to effect price increases. The commentors fear that an interpretation more restrictive than required by the legislation would apply in the case of § 271.502(a)(1). One commentor therefore suggested that § 271.502(a)(1) be revised to track the statutory language in section 105(b)(1)(A) of the NGPA to refer to the "price under the terms of the existing contract." We agree and we have revised § 271.502 (a)(1) to track the appropriate statutory language. This change should allay the apprehensions of those commentors who feared that fixed or indefinite price escalator clauses in contracts were abrogated by § 271.502(a)(1).

One comment suggested adding a new section which would provide, inter alia, that the mere establishment of ceiling prices under the NGPA shall not trigger indefinite price escalator clauses in existing intrastate contracts. Only prices actually paid for sales actually made under the NGPA would trigger such clauses. This is similar to language at page 83 of the Joint Explanatory Statement of the Committee on Conference and reflects, in our opinion, the general intent of Congress with respect to sales under all existing contracts, whether inter- or intrastate. Accordingly as discussed above, we have added a new section 270.205 which provides that the establishment of maximum lawful prices under the NGPA shall not trigger "indefinite price escalator provisions," as defined in the NGPA in either existing intrastate or interstate contracts.

A comment suggested that § 271.502(a)(2) should be revised to allow the § 271.802 stripper well maximum lawful price to apply, instead of the new natural gas price, in any case where there is no contract price for such month or when prices for life-of-well contracts are established from time to time by price lists published by the buyer. We do not find merit in this suggestion. Section 105(b)(1)(B) is quite specific and only provides for the new natural gas rate. However, we have altered the language of § 271.502(a) slightly in order to make clear that that section applies in any case where there is no contract price established on November 9, 1978.

Another comment asserted that the previous language of § 271.504, respecting take-or-pay clauses, may lead to undue burdens where the purchaser has not made payments under a take-or-pay clause or where the parties to the contract have not calculated the volumes to be taken under such clause. It was suggested that the last sentence of § 271.504, dealing with take-or-pay clauses, should either be eliminated or revised. We concur and have established a special provision in paragraph (b) of § 271.505 concerning the effect of take-or-pay clauses which incorporates the commentor's suggested revision. However, we wish to emphasize that this rule is to apply only with respect to the determination of "contract price" on November 9, 1978. It does not apply with respect to any other date (except to the extent the maximum lawful price is determined by reference to the contract price on November 9, 1978.

Another comment sought clarification of the right to collect a contract price under § 271.502 that exceeds the new natural gas price solely because of the inclusion of contractually authorized payments for state severance taxes allowed under § 110 of the NGPA. No modification of Subpart E is required. The rules for determining adjustments for state severance taxes are found in Subpart K of this part.

Uncertainty was also expressed as to whether regulations under Subpart K would cause a roll-back of the contract price to less than $1.00 per MMBtu in a case where it exceeds $1.00 per MMBtu because of reimbursement for state severance taxes. No such "roll-back" would occur if the severance tax provision was in the existing intrastate contract and effective as of November 9, 1978. No revision of Subpart E is required to reflect that fact.

Subpart E sets forth a special rule limiting the effects of modifications of contract terms executed after November 9, 1978. Section 271.505 has been revised to provide in paragraph (a)(1) that no such modification may have the effect of requiring the purchaser to bear any production-related costs which were allocated to the seller under the terms of the existing contract. We have also added a new paragraph (b) which clarifies that paragraph (a) does not preclude contract modifications in the limited circumstance in which a purchaser who was not a party to the existing intrastate contract agrees to bear responsibility to pay for increased production-related costs. The costs contemplated in this new paragraph are those necessary to enable the new purchaser to take delivery of the natural gas subject to the existing contract. We have made this revision in response to a comment pointing out that a new pipeline purchaser may have to install facilities to permit deliveries into its system which would be prohibited under a literal reading of this section. Paragraph (a)(2) of § 271.505 stipulates that no such modification may provide for an earlier date for deliveries than that provided for in the existing contract.

The previous paragraph (b) of § 271.505, which has now been deleted, provided that no modifications to existing successors to existing intrastate contracts may alter the terms of such contracts to provide for a higher price. It was suggested that there was an ambiguity created by paragraph (b) respecting the right of parties to amend existing intrastate contracts where the sales under those contracts otherwise qualify for maximum lawful prices under another subpart of Part 271, and as to whether amendments relating to state severance taxes or production-related costs allowed under § 110 of NGPA are not considered part of the ceiling price. We have deleted the former paragraph (b) of § 271.505 that would have precluded such modifications and have restricted the scope of that section to Subpart E. The Commission wishes to study the matter further before specifying the latitude parties have to effect bilateral modifications to the terms of contracts in existence on November 9, 1978, and invites further comments thereon. Interpretation of contracts remains an initial responsibility of parties thereto.

PART 271 - SUBPART F

Subpart F of Part 271 implements section 106(b) of the NGPA. Subpart F applies to first sales of natural gas under intrastate rollover contracts, and sets forth the procedure for determining the maximum lawful price applicable to such sales.

Tables are provided in the regulation for the prices permitted to be charged under section 106(b)(1) and section 106(b)(2). As is the case with sales qualifying under Subpart E, persons who sell gas pursuant to intrastate rollover contracts may collect the maximum lawful prices without prior Commission approval. Reporting requirements with respect such sales are found in Part 276.

The maximum lawful price under Subpart F for first sales of natural gas under section 106(b)(1) of the NGPA is the higher of (a) the maximum price under the expired intrastate contract in the month of expiration as escalated by the monthly equivalent of the annual inflation adjustment factor, or (b) $1.00 per MMBtu escalated from April 1977 by the same inflation adjustment. Section 271.602(b) provides for the maximum lawful price for natural gas which may be charged for a certain state or an Indian tribe's natural gas production interests under section 106(b)(2) of the NGPA.

Subpart F also contains a special rule similar to the rule in § 271.505. Section 271.604 provides that no intrastate rollover contract may have the effect of shifting to the purchaser, production-related costs which were allocated to the seller under the expired contract.

We received one comment asserting that § 271.505 as proposed might have an adverse effect on interstate pipelines seeking to gain intrastate natural gas. The commentor suggested that § 271.505 should not operate to preclude intrastate rollover contracts from requiring the purchaser to bear costs of installing facilities necessary for the purchaser to take physical delivery of the gas. We have added a new paragraph (b) to this section which provides that a new purchaser may agree to incur increased production-related costs if such costs are necessary for the purchaser to take delivery of the natural gas. We deleted paragraph (b) of the previous draft which related to modifications of delivery dates after having concluded that such a restriction is unnecessary.

One comment asserted that Subpart F may not permit persons making final sales under intrastate rollover contracts to collect severance taxes, borne by the seller and allowed under section 110 of the NGPA, in addition to the maximum lawful price.

The rule is not intended to restrict the collection of contractually authorized maximum lawful prices for which sales otherwise qualify. However, where the contract is silent as to payment of state severance taxes, the seller shall be presumed to be obligated to pay these taxes.

Finally, a comment requested a clarification of the effect of Subparts E and F in cases where sales were being made on November 9, 1978, pursuant to limited term or emergency sales contracts. As the November 15, 1978, notice stated, natural gas sold in interstate commerce under such contracts is excluded from the definition of "committed or dedicated to interstate commerce" under section 2(18) of the NGPA. Accordingly, the maximum lawful prices of Subparts E and F may apply to such sales.

PART 271 - SUBPART G

Subpart G of Part 271 implements section 107 (a) of the NGPA, which applies to first sales of natural gas from deep high-cost natural gas wells. It contains a special rule in § 271.704 clarifying the method of determining the depth of a well.

Section 107 of the Act authorizes the Commission to establish incentive prices for gas from geopressurized brine, occluded natural gas from coal seams, and gas from Devonian shale. It also authorizes the Commission to establish incentive prices for gas produced under other conditions as the Commission determines present extraordinary risks or costs.

This interim regulation does not attempt to implement the provisions of section 107 except as that section specifies prices for deep high-cost gas wells. Practical considerations have precluded our undertaking that effort at this time.

Comments suggested that the special rule in § 271.704, which provides the method of measurement to be used in this subpart, is "inapplicable to offshore wells." It was requested that for offshore wells the measurement be made from the floor of the drilling rig rather than from the surface of the ground. As written, the regulation reflects what the Commission believes to be the appropriate point from which to measure the depth of the well. However, the Commission specifically requests additional comments with supporting data on the appropriate point from which to measure the 15,000 foot depth for offshore production.

PART 271 - SUBPART H

Subpart H of Part 271 implements section 108 of the NGPA, which is applicable to first sales of natural gas produced from stripper wells. This subpart contains definitions of terms used in section 108, and prescribes several special rules intended to assist in implementation.

Section 108 of the NGPA provides a maximum lawful price for stripper well natural gas, and prescribes a definition for stripper well gas. According to the general rule prescribed in section 108(b)(1) of the statute, natural gas is stripper well natural gas if, during the 90-day production period preceding the date on which application is made for a determination, the well produced nonassociated natural gas at its maximum efficient rate of flow and did not exceed an average of 60 Mcf per production day. Natural gas may qualify as stripper well natural gas regardless of the spud date for the producing well. Section 108(b)(2) also provides that a well may, after initial qualification, continue to qualify as a stripper well if production exceeds 60 Mcf per day during any 90-day production period, so long as the increased production is determined to have resulted from the application of recognized enhanced recovery techniques.

Section 271.803 of Subpart H defines "recognized enhanced recovery techniques" and "nonassociated natural gas." The definition of "recognized enhanced recovery techniques" includes processes or equipment which increase the ultimate recovery of gas from a well and excludes techniques or equipment necessary for normal well maintenance, repair or replacement.

The definition of "nonassociated natural gas" would permit a stripper well to qualify under this subpart if it produces crude oil in volumes which do not exceed specific limits. The rule provides for a sliding-scale ratio of natural gas to crude oil production. If a well produced an average volume of between 50 and 60 Mcf of gas per production day in the 90-day production period, it would qualify as a stripper well, provided that it produced no more than 1 barrel of crude oil during the same period. If, on the other hand, a well produced an average volume of between 30 and 50 Mcf per production day, it would qualify if crude oil production did not exceed 2 barrels per production day. Wells below 30 Mcf would qualify if crude oil production did not exceed 3 barrels per day.

Section 271.804 sets forth special rules which interpret and apply terms used in the NGPA. Section 271.804(a) and (b) concern the methodology for measurement of production from a well. Section 271.804(a) states that the volumetric basis for determining the rate of production from a single well is the total volume of gas produced from all producing intervals of the well.

Section 271.804(b) applies when the wells are not individually metered. In this circumstance, jurisdictional agencies may average rates of production in order to determine whether particular wells are stripper wells. For example, if six wells were attached to a single meter, and the meter showed deliveries averaging 360 Mcf per production day or less, presumptively all wells would qualify. If, on the other hand, deliveries from the six wells averaged 370 Mcf per production day, then presumptively, none of the wells would qualify. In either case, alternative evidence may be offered in rebuttal to establish qualification or the lack of qualification.

Section 271.804(d) is a rule applying the statutory requirements with respect to "maximum efficient rate of flow" (MER). The section sets forth the statutory requirement. It also provides that a well is presumed to have produced at its MER during the 90-day production period if it produced an average volume of 60 Mcf or less per production day during a 12-month period ending concurrently with the 90-day production period upon which the determination is based. There may, however, be situations in which a 12-month production history is not available. In such situations, the jurisdictional agency may look to other types of evidence, such as flow tests, which would measure the production capability of a well, or it may defer making the determination for a time necessary to acquire and submit a 12-month production history. If the agency defers the determination, the applicant would, if contractually entitled, be able to collect the stripper well price subject to refund.

The special rules contained in § 271.804(d) are designed to create a presumption upon which the jurisdictional agency may rely to determine that the well for which a determination is sought produced at its maximum efficient rate of flow during the 90-day production period upon which the application is based. **This presumption is not conclusive, however.** If results of well flow tests or other tests designed to determine the production capability of a well are available, the jurisdictional agency may rely on such results or other substantial evidence to make the factual finding that the well produced at its maximum efficient rate of flow.

Section 271.804(e) is a special rule which permits wells to retain stripper status despite increases in production above the 60 Mcf per day level, provided the increase is attributable to seasonal fluctuations. Jurisdictional agencies may make the determination that a well is seasonally affected on the basis of production history over a 24-month period if production from the well has not and cannot reasonably be expected to have exceeded an average of 60 Mcf per day for any 12-month period.

Section 271.805 is a rule implementing section 108(b)(2) of the NGPA. The rule disqualifies wells which, subsequent to the jurisdictional agency determination, produce quantities of gas in excess of the amounts permitted by the law and this subpart.

This rule provides for a reporting mechanism to monitor the continued qualification of the well. Both the operator of the well and the purchaser of the gas are obligated to report any increase in gas production above an average of 60 Mcf per production day for any 90-day production period. Unless the operator receives a determination from a jurisdictional agency that the increase was due to the application of recognized enhanced recovery techniques, or is determined to be seasonally affected, he may no longer collect the stripper price for the well. If the operator files a petition for a determination that the increase in production results from enhanced recovery techniques or seasonal fluctuations, continued collection of the stripper well price shall be made subject to refund for deliveries made after the last day of the applicable 90-day or 12-month production period.

Most of the comments on this section were addressed to the proposed definition of "nonassociated natural gas." Many of the comments were made by persons from the Appalachian area -- Ohio, West Virginia, Pennsylvania, and Kentucky. Comments from the State of New Mexico also expressed concern over the definition of "nonassociated natural gas."

With only one exception, all of the parties concluded that the Commission's proposed definition of "nonassociated natural gas" was too restrictive. More specifically, they suggested that to base eligibility under this subpart on the showing that the well produced an average of one barrel of oil or less per production day for a 90-day production period will exclude many marginal wells in the Appalachian area from qualifying as stripper wells.

These comments asserted that the "one-barrel" limitation will result in the premature plugging and abandonment of marginal gas wells in the area which in turn could result in a permanent loss of reserves. It was argued that the definition was unduly restrictive and was neither required nor contemplated by the law.

As is noted above, the Commission has decided to expand its definition of "nonassociated natural gas" so as to permit, in certain instances, a higher crude oil-to-natural gas production ratio than was originally proposed. The new definition uses a "sliding scale" which permits greater crude oil production as gas production declines. This approach is predicated in part on the economics of producing oil and gas from a marginal gas well. The new definition recognizes the limited revenues from marginal wells and attempts to provide a reasonable incentive to preserve this production. The Commission believes that the definition is a reasonable one, and is of the type contemplated by the authority given it in section 501(b) of the NGPA.

It was suggested that the proposed special rule which requires the total volume of natural gas produced from the well be utilized for purposes of calculating the average rate of production, regardless of whether the well is completed in more than one interval (§ 271.804(a)), be deleted. In support of this recommendation, it was argued that the proposed definition was contrary to the statutory intent of maintaining production from economically marginal wells.

In several instances, the NGPA clearly distinguishes between the terms "completion location" and "well." The terms are separately defined in section 2 of the NGPA. In sections 102 and 107 the distinction between "completion location" and "well" is clearly the basis for several determinations. However, section 108 provides that the stripper well natural gas classification can only be obtained for production from a "well." Unlike other sections, no mention is made of a "completion location" within a well. Accordingly, we have not adopted this recommendation.

One comment recommended that the special rule on "seasonally affected wells" (§ 271.804(e)) should be deleted because section 108 does not provide a statutory predicate for such a rule. The Commission disagrees. Production from a well often varies as a result of the pressure differentials created by temperature fluctuations. A rule that ignores this occurrence would place an undue administrative burden on producers, states and the Commission. Many wells would have to go through the qualification and disqualification process each year. For these wells the Commission believes that once a well qualifies as a stripper well, the provision permitting it to remain qualified as long as production does not exceed 60 Mcf per production day on a yearly basis, where the well is determined to be seasonally affected, is both practical and within the spirit and intent of the law. The Commission believes that the practical result of not providing this exception to the 60-Mcf-per-production-day rule requires this exercise of its rulemaking authority under section 501(a) of the NGPA.

It was also proposed that §§ 271.804, 271.805, and 271.806 be amended to delete references to "90-day production period" and to insert in its place the phrase, "3-month production period." It was argued that this change will greatly simplify the administration of the regulations. It was further argued that because production records are kept on a monthly basis rather than a daily basis, it is impossible to calculate the 90-day production period figure required by section 108 of NGPA.

The Commission has incorporated the statutory language in its regulations. The Commission recognizes that production records and billing statements are often kept on a monthly basis. Consequently, the Commission believes that reasonable assumptions premised upon such records, which attempt to calculate average production per production day for the 90-day production period upon which the application is based, will provide the jurisdictional agency with sufficient evidence upon which a determination may be made.

Several comments requested that we define "recognized enhanced recovery techniques" with greater specificity. Some comments suggested that the proposed definition should be drafted to specifically exclude wellhead compression techniques.

The Commission believes that the term "recognized enhanced recovery techniques" should not be more explicitly defined until more experience has been gained as to what specific equipment and processes should be included. It is anticipated that the Commission will identify specific enhanced recovery techniques in the future. In the interim, the Commission will address the question of whether enhanced recovery techniques have been applied on a case-by-case basis. After some experience, the Commission will determine whether general rules are either necessary or desirable.

It was pointed out that the determination as to what constitutes enhanced recovery techniques under § 271.803(a) should be left to jurisdictional agencies and not to the Commission. This suggestion is contrary to the statutory requirement of section 108(b)(2). This section requires that the Commission provide a rule for continued qualification of nonassociated natural gas where such natural gas is produced from a well when production from such well exceeds 60 Mcf per production day as a result of the application of enhanced recovery techniques.

The rule promulgated by the Commission to implement this section relies on the expertise of both the jurisdictional agencies and the Commission. This reliance is required at this time since the question of whether enhanced recovery techniques have been applied will often turn upon factual considerations.

Finally, the Commission was asked to require that all flow tests be made by employees of jurisdictional agencies or independent engineers certified by a jurisdictional agency. At this time, we find that this requirement is unnecessary.

PART 271 - SUBPART I

> Subpart I of Part 271 implements section 109 of the NGPA by setting a maximum lawful price for "other categories of natural gas," that is, for first sales of natural gas that are not covered by any maximum lawful price under any other subpart of Part 271. [Emphasis supplied.]

Section 109 of the NGPA presents an important question of interpretation. The portion of section 109(a) which precedes paragraph (1) limits section 109's application to "natural gas which is not covered by any maximum lawful price under any other section of this subtitle." [Emphasis supplied.] However, paragraph (1) of section 109(a) specifically includes natural gas "produced from any new well not otherwise qualifying for a higher maximum lawful price." [Emphasis supplied.] The question presented is whether the general language in section 109(a) is intended to limit the scope of the examples which follow (so that new wells which qualified for a lower price under another section of the NGPA would be excluded from section 109), or whether the specific examples override the general statement of the scope of section 109 (so that new wells otherwise subject to a maximum lawful price which is lower than the section 109 price nonetheless would be eligible for the higher section 109 price).

In this regard, it should be noted that the portion of section 109(a) which precedes paragraphs (1) through (4) introduces those paragraphs with the word "including." Under general rules of construction therefore, it would appear that paragraphs (1) through (4) are qualified and controlled by the general statement of applicability which limits section 109 to first sales not covered by any maximum lawful price. For this reason, the Commission is of the view that the first interpretation is correct and has incorporated that interpretation in the regulations implementing section 109. A special rule in § 271.904 provides that the maximum lawful price in this subpart applies to a first sale of natural gas described in paragraphs (1), (2), (3), or (4) of section 109 (a) only if that first sale is not covered by any other maximum lawful price in the NGPA.

Several comments were received which argue that the interpretation of section 109(a) which is reflected in the regulations is wrong. These comments state that the specific examples set forth in section 109(a)(1) through (4) are intended as additions to the general category set forth in the portion of section 109(a) which precedes paragraph (1). We specifically invite further comments on this issue.

Finally, a comment was submitted recommending that § 271.904(a) contain a reference to § 273.201 in order to help eliminate confusion over the right of the producer initially to apply for the section 109 price under the interim collection regulations. The recommendation is in error in that natural gas which qualifies for the interim rate under § 273.201 must also be the subject of an application for a determination under Subparts B, C, G, or H of Part 271. The natural gas subject to the price established in § 271.904(a) under section 109 of the NGPA cannot, by definition, qualify under those subparts.

PART 271 - SUBPART K

Subpart K of Part 271 of the Commission's interim regulations implements section 110 of the NGPA. That section permits a first sale price of natural gas to exceed the applicable maximum lawful price for that sale to the extent necessary to recover state severance taxes borne by the seller. It also permits a first sale price of natural gas to exceed the applicable maximum lawful price for that sale to the extent necessary to permit the recovery of allowances for certain production-related costs which are a component of just and reasonable rates established under the NGA and certain production-related costs for natural gas not subject to just and reasonable rates under the NGA, if such costs are borne by the seller, and allowed by the Commission.

Section 271.1101(a) incorporates the definition of "state severance tax" contained in section 110(c) of the NGPA. This definition includes most types of production taxes, including ad valorem taxes which are based upon the amount of production. Therefore, the Commission believes it is unnecessary to specifically include the various types of severance taxes in the definition. Subparagraph (2) of paragraph (a) of § 271.1101 incorporates the statutory exclusion of taxes, which were enacted on or after December 1, 1977, and which do not apply equally to natural gas produced for delivery to interstate commerce and gas produced but not so delivered.

Section 271.1102 states that the maximum lawful price applicable to a first sale of natural gas will not be deemed to be exceeded, if the first sale price exceeds the maximum lawful price only to the extent necessary to recover state severance taxes borne by the seller. Paragraph (b) of § 271.1102 acknowledges that the just and reasonable rates applicable to natural gas produced from the Permian Basin area already include a specific allowance for state severance taxes. Therefore, those amounts are excluded from the provisions of the section so as not to permit double-recovery by the seller of State severance taxes for production in the Permian Basin which is subject to the Permian Basin area rate. State severance taxes actually paid by the seller in excess of 2.6 cents per Mcf for large producers and 3.05 cents per Mcf for small producers will be permitted to be recovered under paragraph (a) of § 271.1102 (so long as such taxes are paid by the seller).

Section 271.1103 contains a requirement that sellers retain records verifying the amount of state severance taxes borne by the seller for transactions in which the maximum lawful price is exceeded as a result of the addition of amounts necessary to recover state severance taxes.

Section 271.1104 provides that an applicable maximum lawful price for a first sale may be exceeded to the extent necessary to recover certain allowances permitted under the Natural Gas Act. These allowances include the area-wide gathering allowances and the allowances permitted for the delivery of offshore natural gas currently described under Part 2 of the Commission's regulations. While references to both the national rates for sales from wells commenced on or after January 1, 1973 (§ 2.56a) and those from wells commenced prior to that date (§ 2.56b) are given, these allowances are identical. The two references were supplied to make it clear that persons who were receiving such allowances, under either provision, will continue to receive them if they are qualified. Qualifications for these allowances are set forth in paragraph (b). To receive these allowances for a first sale of natural gas the seller must (1) be selling natural gas which was committed or dedicated to interstate commerce on November 8, 1978, and for which a just and reasonable rate was in effect on that date; and (2) must meet the applicable requirements of §§ 2.56a(d), 2.56b(e), 2.56a(e), or 2.56b(f) of this chapter.

Several comments, particularly those dealing with the problems of resellers, requested the inclusion of what is now § 271.1104. The Commission believes that while the allowances are based on cost data supplied several years ago, such allowances should be permitted inasmuch as they were permitted for rates previously set by the Commission. It would serve no regulatory purpose to require sellers making first sales under these previously established just and reasonable rates to apply for such allowances under § 271.1105 when such gathering allowances, as permitted in Part 2 of this chapter, have already been deemed just and reasonable.

Section 271.1105 establishes a procedure under which the Commission will consider applications for amounts to be collected in addition to maximum lawful prices to the extent necessary to recover certain production-related costs.

Paragraph (b) of § 271.1105 precludes the filing of any application for such an allowance if the natural gas subject to the first sale was committed or dedicated to interstate commerce as of November 8, 1978, and was subject to a just and reasonable rate in effect at that time. It also precludes applications with respect to natural gas subject to an existing intrastate contract, successor to an existing intrastate contract, or an intrastate rollover contract.

Several comments focused on the exclusions in this section. The exclusion of committed or dedicated natural gas is not an attempt on the part of the Commission to decide the issues now before the Commission on rehearing in Phillips Petroleum Company, Docket No. CI77-412, et al. Instead, the exclusion of natural gas for which a just and reasonable rate was established by the Commission on or before November 8, 1978, from the operation of § 271.1105 reflects the Commission's intention to reserve these issues for decision in the Phillips case rather than in the interim regulations.

The subsequent and separate order in the Phillips rehearing will set out the Commission's policy in this regard. The exclusion of natural gas sold intrastate subject to existing contract obligations reflects a similar view: namely, that the existing contract provisions reflect the allocation of costs of production as they were contemplated by the parties at the time the contract was negotiated. These provisions, and more importantly any change in such provisions, would change the price actually paid for the natural gas subject to the existing contract. The NGPA in sections 105 and 106(b) establishes a pricing mechanism which relies upon the prices and the contractual terms as they relate to price as such prices and terms were in existence on the date of enactment of the NGPA. It would be contrary to the intent of Congress to permit a change in such prices and terms that would have the effect of increasing the total costs borne by the purchaser for acquiring the very same commodity as he was acquiring for a lower price before date of enactment. This would also be contrary to the intent of this provision and the NGPA and would unnecessarily complicate the implementation of sections 105 and 106(b) of the NGPA. The Commission believes that the exclusion contained in § 271.1105(b)(2) is consistent with Congressional intent to establish maximum lawful prices for such contracts by reference to the terms and conditions as they relate to the allocation of production-related costs as they were in existence on the date of enactment.

The interim regulations provide, in paragraph (c), that applications to the Commission will be considered for costs of gathering, liquifaction or transportation only if those latter activities occur off the lease from which the natural gas was produced. It is the intent of the Commission that the costs of gathering, liquifaction, or transportation should only be permitted to the extent that they are not activities normally performed in the production of natural gas. The Commission believes that costs of gathering, liquifaction, and transportation when performed on-the-lease are activities normally performed by a producer in production of natural gas. Where such costs for activities performed on-the-lease are extraordinary, a seller may seek an adjustment pursuant to section 502(c) of the NGPA to prevent special hardship, inequity, or an unfair distribution of burdens. Such relief is specifically recognized in § 271.1106.

The regulation does differ from the notice of proposed rulemaking in that the term "off-lease" has been revised to read "off of the lease from which the natural gas was produced." This change was made in response to a comment in the proposed regulation that the original language would unfairly impact upon operations where such activities were performed for one producer by another producer but off of the lease from which the natural gas was produced.

Paragraph (d) sets out certain quality standards for natural gas. Only applications for recovery of that portion of costs necessary to bring gas to a quality greater than specified in the standards will be considered under this section. This section provides an exception to this rule for transactions involving direct sales to end users. With respect to the pipelines, the Commission has determined after a review of existing contractual terms and data filed with the Commission, the standards specified are those which are normally required for pipeline quality natural gas. The Commission does not have sufficient data to draw the same conclusions with regard to direct sales to end users. The Commission requests further comment on these standards.

A substantial number of comments were received on this section. Some comments argued that section 110 of the NGPA addresses only costs relating to the production of natural gas. It was argued that, to the extent costs such as those enumerated under this section are incurred after production, the Commission lacked authority to regulate them under section 110. Second, it was argued that all costs, those respecting processing and treating, as well as those for such activities as gathering and transportation, should be treated together. Third, the method used to identify the minimum quality standards was questioned. It was submitted that such requirements, as set down by the Commission, over-looked the extraordinary costs which may be required to meet the stated conditions. Fourth, it was argued that no minimum standards should be set; that the Commission should merely permit a dollar-for-dollar passthrough of these and similar costs. Finally, the point was raised that if such standards are to be set, they should be made uniformly applicable and they should be based upon area-wide requirements determined after the gathering of more detailed data.

The Commission believes that section 110 of the NGPA does not require that all costs for compressing, gathering, processing, treating, liquifaction, or transportation must be treated together and dealt with identically. Indeed, this reading of section 110 is inconsistent with the fact that the different types of costs are indeed incurred at different times and locations. Treating all such costs as a group is impossible as a practical matter and could not have been intended by the Congress. To restrict the applicability of section 110 to costs borne only by the producers and only to the extent necessary to bring natural gas to the surface of the ground would work a hardship on other "sellers" subject to maximum lawful prices. This result is clearly contrary to section 110 which refers to costs "borne by the seller".

The Commission has provided regulations to permit recovery of costs relating to certain gathering, liquifaction, transportation, and compression under § 271.1105(c). The Commission has also provided for the recovery of costs relating to certain conditioning and treating under § 271.1105(d). These separate provisions are warranted since the costs are similarly incurred during the production cycle.

Several comments were specifically directed to the provisions of § 271.1105(d). These comments argued that the Commission is establishing minimum standards of quality and that the Commission does not have the requisite authority. The Commission disagrees with these comments. First, the Commission is addressing the issue of which costs will be allowed to be added-on to the statutorily specified maximum prices. Section 110(a)(2) specifically states that costs for processing and treating, among other things may be recovered only to the extent "allowed for, by rule or order," of the Commission. The statute does not require the Commission to automatically permit the recovery of all such costs, but leaves to the discretion of the Commission whether to grant the authority to the sellers to recover such costs. In exercising such discretion, the Commission may attach such terms and conditions as it deems appropriate so long as they are not contrary to statutory intent or arbitrary and capricious. On the basis of the discussion set forth in this preamble, the Commission believes that the terms and conditions imposed by these regulations are necessary and appropriate to carry out the intent of Congress in enacting the NGPA.

Standards for determining when the Commission will entertain applications for a determination that the maximum lawful price has not been exceeded as a result of the addition of certain production-related costs are required in order to assure that natural gas for which the maximum lawful prices set by the NGPA are paid is that commodity which is of relatively uniform value to the purchaser. When a price is charged and collected for a specific commodity, such a product is normally deemed to have certain basic qualities which define the item being purchased. The Commission does not believe that Congress, when setting the maximum lawful prices for natural gas, did not anticipate that the sellers would bear normal costs of production in making this commodity useful to the purchaser. The maximum lawful prices were designed to permit the sellers to recoup such costs. Section 110 recognizes that some sellers may incur abnormally high costs of production and permits recovery of those costs in circumstances where the Commission finds such recovery to be warranted.

The statute envisioned that the Commission could perform these responsibilities either by rule or on a case-by-case basis. Recognizing the differences in production cost that may occur, the Commission, through these regulations, is utilizing both rulemaking and particularized orders to implement section 110.

Section 271.1100(b) excludes from the operation of § 271.1104, § 271.1105, and § 271.1106, natural gas produced from the Prudhoe Bay Unit of Alaska and transported through the system approved under the Alaska Natural Gas Transportation Act of 1976 (ANGTA). Prudhoe Bay is a new and unique producing area for which there is no history of industry practice relative to the bearing of production-related costs. Therefore, a separate rule under the provisions of ANGTA for natural gas from that producing area is required and will be promulgated by the Commission in the immediate future.

This exclusion received some comment. One comment, while agreeing that natural gas produced from Prudhoe Bay should be treated differently from that produced in more conventional settings, evidenced a concern that it would not be so treated. Instead, it was feared, the Commission would seek to apply to this natural gas such standards as were set forth in Subpart K. In addition, the same comment raised the question of how natural gas produced from areas similar to that of Prudhoe Bay would be treated. Both of these concerns turned upon the view that as proposed, the regulation did not touch upon a typical situation of costs for production or transportation. A second comment took issue with the Commission's consideration of separate costs associated with the Prudhoe Bay effort. The gravamen of this comment was two-fold: first, that excepting Prudhoe Bay gas resulted in continued uncertainty as to the Commission's treatment of this natural gas; second, that a rulemaking under ANGTA, as opposed to the NGPA, was neither warranted nor proper.

The failure to except other, similar production areas (as for example the North slope), was intentional. It is envisioned that to the extent such other areas evidence particular characteristics which require special treatment, either more data will be available whereby they can be properly treated, or they can be considered under § 271.1106. Prudhoe Bay requires special consideration, for in that case data is available to assist the Commission in considering the questions attendant to maximum lawful pricing provisions. As already mentioned, these questions are to be dealt with by a special rulemaking.

The issue as to which statute applies for purposes of providing for Prudhoe Bay is, like the issue of the actual treatment of production-related and similar costs for this production area, best addressed within the setting of the proposed rulemaking. Suffice it to say that the Commission believes that its authority under section 110 of the NGPA is broad enough to make special provisions and exceptions as between regions if good cause can be found. Considering the state of production from Prudhoe Bay, the Commission is of the opinion that the exception is, at this stage, required.

PART 273

The purpose of Part 273 is the establishment of procedures for the interim collections authorized by section 503(e) of the NGPA. Section 503(e) permits interim collection, subject to refund, of those prices for certain categories of natural gas for which a determination of eligibility is made by a jurisdictional agency and is subject to review by the Commission. These categories are new gas and certain OCS gas (as defined in section 102 of the NGPA), gas from new onshore production wells (section 103), high-cost natural gas (section 107) and stripper well natural gas (section 108).

Description of the regulations. Part 273 is divided into three subparts: general provisions, interim and retroactive collection provisions, and the procedures for refund guarantees and refund payments.

Subpart A which contains general provisions has not been revised. Few comments on this subpart were received. Section 273.101 states that eligibility under these regulations to collect a maximum lawful price for a particular category of gas does not give a seller the right to collect a price which is higher than that permitted by the sales contract. Section 273.102 defines a "final determination" for purposes of this part as a determination of eligibility by the jurisdictional state or federal agency which is no longer subject to review and reversal by the Commission or the courts except pursuant to section 503(d)(1) of the NGPA. Section 273.103 requires each seller to file an annual report of any collections and refunds under this part.

One comment noted that the annual report requirement would be burdensome to small intrastate producers. Another comment suggested that this report replace the specific filing requirements of Subpart B for each first sale. The Commission believes that specific filings and the annual report are necessary to monitor collections and refunds under this part. Prior to the end of the first reporting period, on December 31, 1979, the Commission will issue a rule specifying the form and scope of the annual report.

Subpart B of Part 273 provides the specific rules for interim collections and for retroactive collections where the maximum lawful price established by a final determination exceeds the price collected on an interim basis. Section 273.201 establishes a transitional rule which is limited to first sales from new wells. It was suggested that the eligibility for interim collections under § 273.201 be broadened to include first sales of natural gas, in a new reservoir that is produced from an old well or is stripper well natural gas. The limitation to new wells is taken directly from section 503(e)(1) of the NGPA and applies the definition of new wells found in section 2(3) of the NGPA. It will not be modified. Sales of stripper gas or new gas from an old well may qualify for interim collections under § 273.202 and for retroactive collections under § 273.204.

Under the regulations proposed for comment, the transitional rule would have terminated on March 1, 1979. The interim regulations have been revised to permit collections under this provision to continue until the jurisdictional agency issues a determination of eligibility. A seller may collect, subject to refund, the price determined under section 109 of the NGPA, if an application for determination is submitted to the jurisdictional agency by March 1, 1979. This price may be charged and collected beginning on the date on which the seller completes the filing requirements under this section and ending on the date of notice to the Commission of a determination by the jurisdictional agency for the well from which the sale is being made. One comment requested a grace period allowing full interim collections for December 1978 if the filing required under this section is submitted by December 31, 1978. This modification of the statutory scheme will not be adopted. The retroactive collection procedure under § 273.204 may be available to recoup charges and collections which cannot be made immediately because of delayed compliance with the filing requirements.

To qualify for the transitional collection authority, the proposed regulation stated that a seller must file with the Commission a sworn statement that the sale is being made from a new well which is eligible for the price to be collected, and that the seller has filed an application for determination with the jurisdictional agency or will do so by March 1, 1979. Two comments noted that some jurisdictional agencies do not permit filings to be made by sellers who are not actually operating the well. Therefore, the filing requirements have been modified to permit a sworn statement that the seller will cause an application to be submitted, on or before March 1, 1979, by a person authorized to do so by the rules of the jurisdictional agency. A seller who cannot make that sworn statement in good faith may substitute a sworn statement by a person eligible to file a timely application.

After an application for determination has been filed, a seller may use the procedure established by § 273.202 to collect, subject to refund, the maximum lawful price for which the sale is believed to be eligible, for a period of up to eighteen months (or twelve months where collections under this section begin on or after May 1, 1979). Alternatively, if the application for determination was filed by March 1, 1979, the seller may continue to collect the price specified in § 273.201(a) until the Commission receives notice of the determination by the jurisdictional agency.

The proposed § 273.202 rule has been modified to some extent. To qualify for interim collection authority under § 273.202, a seller must fulfill certain filing requirements, by submitting a sworn statement of eligibility, a duplicate of FERC Form 121 accompanying the application for determination, and either a statement certifying that a portion of the amounts collected under this procedure will be placed in escrow or secured by surety bond or a release from this obligation executed by the purchaser.

The authorization to make interim collections of the price for which the sale is believed to be eligible terminates on the date on which the Commission receives a notice that a determination of eligibility has been made, or after eighteen months (or twelve months where collections under the section begin on or after May 1, 1979) where no determination has been made. After such termination, the seller may not use this procedure again for this sale or any other sales from the same well. Where a determination has not been made within eighteen months and the authority to collect a price under this section ends, a seller may use § 273.201 to collect the price authorized by that section; but only where the application for determination was filed on or before March 1, 1979. Otherwise, the seller will be limited to collection of the applicable maximum lawful price specified in Subparts D, E, F, or I of Part 271. After an initial determination is made, § 273.203 can be used to collect the price established by that determination.

Three significant questions were posed by the comments on the proposed § 273.202. In addition, there was one suggestion that each of the items to be filed under paragraph (c) are not needed. Many comments requested deletion of the proposed condition in paragraph (a) that collections cannot begin under this section until the appropriate jurisdictional agency has filed with the Commission an undertaking to diligently consider and decide applications and the report on procedures to be used by the agency, as required by § 274.105. These comments argue that this qualifying condition is unlawful or inequitable, chiefly because compliance is beyond any seller's control. The comments recommend that sellers be permitted to make interim collections under this section after an appropriate filing with this Commission.

Section 503(e)(2) of the NGPA provides that the price sought in an application for determination can be charged and collected upon filing of an application. The Commission believes that it is particularly important that higher prices dependent on determinations of eligibility should not be charged and collected, subject to refund, until a jurisdictional agency has undertaken to consider these applications and has established procedures to make determinations on these applications. Moreover, collections under this section should not continue if a jurisdictional agency is not actively proceeding to make specific determinations.

To better express our intent, the proposed § 273.202(a) will be changed in two respects. First, this condition will be restated as a requirement that no filing to charge and collect a maximum lawful price under this section may be submitted to this Commission until the jurisdictional agency to which the application for determination has been made has filed the report and undertaking required by § 274.105. As noted in the discussion of Subpart A of Part 274, the form of the undertaking has been modified to require the jurisdictional agency to state that it will take such steps as are reasonably necessary or appropriate to perform its functions under Part 274. Second, unless a jurisdictional agency has notified the Commission by March 1, 1979, that it is actively processing the applications for determinations, then authority to make interim collections under this section will be suspended with respect to deliveries made during the period from March 1, 1979, until the date on which the jurisdictional agency gives notice that the applications are being processed. During this suspension period, collections under § 273.201 will be permitted if an application was submitted to such agency by March 1, 1979. A similar change is made in § 273.204 so that later retroactive collections will also be suspended and not permitted over the same period.

One comment has also addressed two of the other paragraphs within § 273.202. First, it is argued that the limitation of interim collections under this section to no more than eighteen or (twelve) months should be deleted as "unreasonable and inequitable", again because termination of interim collections under this section could result from inaction by a jurisdictional agency beyond the control of any seller. The Commission does not believe that this limitation is unreasonable or unnecessary. The Commission will consider a revision of this rule if it proves to be unworkable or if substantial hardships result. In any event, retroactive collections under § 273.204 or additional interim collections under § 273.201 may be available in such circumstances.

There is a final suggestion that paragraph (d) of § 273.202 should be modified to permit successive interim collections of the maximum lawful price for stripper natural gas; for example, where there is a determination that a well is not a stripper well under section 108 of the NGPA, but another application for determination is properly submitted after a change in the level or character of production from that well. This suggestion will not be adopted. Upon a final and later determination that a well qualifies as a stripper well, the seller may be eligible to use the provisions of § 273.304 to collect retroactively the maximum lawful price for stripper natural gas, plus carrying charges back to the date on which the later application was filed.

When the jurisdictional agency issues its determination of eligibility for the well from which the sale is being made, § 273.203 authorizes interim collection, subject to refund, of the price established by that initial determination. Within 15 days after interim collection begins under this section, a notice of collections must be filed with this Commission and the jurisdictional agency and also served upon the purchasers. There are no other filing requirements under this section. The Commission will not adopt the suggestions that these limited requirements should be deleted as unnecessary. The authority to collect the price established by the initial determination of eligibility ends when that determination has been reviewed and becomes final. If the Commission does not approve or reverse an initial determination, but makes a final finding that the determination should be remanded to the jurisdictional agency for further consideration, then the seller may continue to collect the price established by the remanded determination for up to six months during reconsideration by such agency.

When a determination of well eligibility becomes final, a seller may immediately collect the price established there for all future sales from that well under the authority of the applicable section of Title I of the NGPA and Part 271 of these regulations. Section 273.204 of this part authorizes the retroactive collection of that finally determined price for all first sales of gas delivered after the application for determination was filed. If this application is filed by March 1, 1979, then retroactive collections may be made for gas delivered on or after December 1, 1978. However, as previously explained, retroactive collections cannot be made for first sales of gas delivered during the period in which a jurisdictional agency is not actively considering the applications for determination that have been submitted. Unless the Commission receives written notification by March 1, 1979, that the jurisdictional agency is then making determinations, later retroactive collections of the finally determined price will not be authorized for the period from March 1, 1979, until the jurisdictional agency gives notice to the Commission that determinations are being made.

Although recognizing that section 501 of the NGPA empowers the Commission to impose conditions on retroactive collections, one comment stated that the "cut-off" of complete retroactive collections, (where the application for determination has not been filed by March 1, 1979) is unreasonable. Otherwise, it continued, producers lacking immediate engineering assistance will be precluded from retroactively collecting the finally-determined price from December 1, 1978 until the date of application for a determination (if filed after March 1, 1979) and thus suggested that the minimum acceptable "cut-off" would be July 1, 1979.

The Commission believes that the current "cut-off" of March 1, 1979, reflects a reasonable balancing of the sellers' need for sufficient time to prepare applications against the burden to be placed on purchasers and their consumers by the accrual of large sums for later retroactive collection. Interstate pipelines commented that retroactive collections "could have substantial adverse repercussions" for them and for their customers.

We should also provide a clarification that the period of retroactive collections is based upon the filing date of a complete application for determination, in compliance with Subpart B of Part 274 and the applicable regulations of the jurisdictional agency receiving the application. Where an application is rejected, either by the jurisdictional agency or after an initial determination by this Commission that the application does not conform to these regulations, then retroactive collections will be authorized from the date on which a conforming application is refiled (or December 1, 1978, if the conforming application is refiled by March 1, 1979).

Conversely, there was one comment that any provision for retroactive collections would be unlawful, because there is no explicit authorization within section 503(e) of the NGPA. In our opinion, a retroactive collection rule is not inconsistent with the statutory language and is mandated by the Statement of Managers and the floor debate on the statute. We have attempted to establish reasonable limitations and conditions on these collections.

Many comments were directed to the qualifying conditions proposed in § 273.204(b); and the interim regulations will reflect several modifications. The proposed subparagraph (1) of § 273.204(b) stated that "[r]etroactive collections may be made only to the extent and in the manner specified by the applicable sales contract (or amendment thereto). . . ." The Commission does not agree with this comment that some explicit statement of this principle is unnecessary although the specific wording has been changed. As that comment recognizes, no price or amount authorized by any of these regulations may actually be collected from the purchaser unless there is sufficient contractual authorization for the payment. Also, we will not accept the other suggestion that a single method for such payments should be mandated, believing that this question should be left to the discretion of the parties within the limits provided by the sales contract and any later amendments. Thus, we will not require that all retroactive amounts must be collected immediately after a determination becomes final or over a period equal to the time during which this obligation accrued. The seller will be required to file a concurrence by the purchaser in the method and amount of retroactive collections.

Proposed subparagraph (2) of § 273.204(b) would have required "full compliance" with all applicable regulations of the Commission as a condition upon any retroactive collections. This requirement has been deleted. The comments reflected substantial confusion about the scope of this subparagraph and argued that it is "overly broad", particularly because of the uncertainties and difficulties which the comments were anticipates during the initial implementation of these regulations. This deletion will not limit our ability to enforce compliance with the NGPA and these regulations.

Similarly, the qualifying condition regarding the seller's obligation to make refunds to the purchaser has been clarified. Subparagraph (2) of § 273.204(c) in the interim regulations states that a seller may not collect a retroactive amount from a purchaser for any sale, until the seller has refunded to that purchaser any amounts due to be refunded to such purchaser for any other sale under the NGPA and this subchapter of the Commission's regulations. Compliance with any separate obligation to refund amounts collected under section 4 of the NGA (rather than under the NGPA) will be monitored and enforced using the Commission's existing producer regulations in Part 154.

Finally, the proposed regulations stated that carrying charges on the amount to be collected retroactively would be permitted "only to the extent agreed upon by the parties" to the sales contract. The interim regulations, § 273.204(c)(5), have been revised to require that any agreement of the parties which provides for carrying charges must be reduced to writing and then filed with the Commission. There were no comments on this provision, except for one question: whether an interstate pipeline is entitled under section 601(c)(2) of the NGPA to guaranteed pass-through to its customers of any carrying charges paid under this section. Consideration of this question is not required at this time. It may be addressed by rule or in specific cases, after carrying charges have been paid by interstate pipelines. We should explain now that section 601(c)(2) of the NGPA does not guarantee automatic pass-through of charges to interstate pipelines under the interim collection provisions.

Interim collections will necessarily precede final determination of the maximum lawful price for such sales. Therefore, interim collections cannot be deemed just and reasonable under section 601(b) and thus cannot qualify for guaranteed pass-through to pipeline customers under section 601(c)(2).

In some instances, the provisions of this part will be used to collect interim prices for first sales of natural gas which was committed or dedicated to interstate commerce on November 8, 1978, the day before the date of enactment of the NGPA. Under section 601(a)(1)(B) of the NGPA, sales of committed or dedicated gas will be subject to the Commission's jurisdiction under the Natural Gas Act, particularly to the filing requirements for making a rate change, until a final determination that such gas qualifies as high-cost gas, new gas, or gas produced from a new onshore production well. The relationship between the filing requirements of these NGPA regulations and Part 154 of the regulations under the NGA is discussed in the Commission's final rule amending § 154.94(h) of Part 154, issued November 17, 1978 in Docket No. RM79-4, as Order No. 15. Under the final rule, in the case of interim collections for first sales of gas which remain subject to the requirements of the NGA, full compliance with the filing requirements of this part and the other regulations under the NGPA will also satisfy the additional filing requirements under section 4(e) of the NGA and Part 154 of the Commission's regulations. Thus, a seller which makes the filing required by § 273.202(c) may collect the price specified in the application for determination of eligibility without submitting the prior notice of rate change required by § 154.94 of the Commission's regulations under the NGA.

Subpart C of this part establishes procedures to assure that any interim collections will be refunded as necessary and for the actual payment of refunds with interest after a final determination that a first sale does not qualify for a price already collected under this part. Section 273.301 establishes a general obligation upon each seller to refund any collections which are not authorized by the NGPA and these regulations, if ordered to do so by the Commission at any time. For example, a determination can be reconsidered and modified after it becomes final, if it was based on an untrue or misleading statement of material fact in the application for determination. As a result of that modification, additional refunds could be ordered even though the seller would have already discharged any specific refund obligations under § 273.302 and the prior final determination.

Section 273.302 sets out specific procedures for refund assurance and payment. A seller's potential liability to refund any interim collections must first be secured by the filing of a written undertaking to make refunds using one of the forms set out in § 273.302(b). A seller must file a series of refund undertakings covering collections for sales from the wells identified in an appendix to each successive undertaking, or one blanket undertaking which is a general agreement to make all refunds which may be required under the NGPA.

Interim collections that are made under § 273.202 pending an initial determination of eligibility and the proper price are subject to a further requirement providing additional refund assurance. Section 273.302 of the proposed regulation requires the seller to secure by surety bond or to place in escrow the portion of the price collected under § 273.202 which exceeds the maximum lawful price determined under section 109 of the NGPA (for sales from new wells) or the maximum lawful price under sections 104, 105 or 106 of the NGPA (for sales from old wells).

This provision was opposed by comments from a variety of persons. These comments argued that a mandatory escrow provision would be unduly burdensome to producers and costly to consumers who would receive a lower rate of interest on escrowed refunds. A corporate guarantee or undertaking to make refunds should be sufficient, according to these comments, because this simple procedure has been used successfully by the Commission to provide ample assurance of refunds under the NGA. In response to these many comments, the proposed § 273.302(c) has been modified to require in the **interim regulations that a portion of the interim collections** under § 273.202 must be secured by a surety bond or placed in escrow, unless the purchaser by written agreement releases the seller from this requirement for additional refund assurance. Thus, the Commission will accept initially a judgment by the purchaser on the seller's ability to make future refunds; but, in specific cases under subparagraph (b)(3) of this section, additional refund assurance may be ordered by the Commission at any time for any interim collections under Subpart B.

Other provisions of § 273.302 require each seller to maintain full records of the amounts that are collected subject to refund, and to make the actual refunds by cash or check within forty-five days after the applicable determination of eligibility becomes final. There is no provision for any other method to discharge a refund obligation, such as by work-offs, commitment of additional reserves to each purchaser, or reduction of the price charged for future deliveries. Permission to use an alternative refund method will be granted only in exceptional cases.

PARTS 274 AND 275

General. Under certain sections of the NGPA, eligibility for the maximum lawful price established by the NGPA is initially determined by the state or federal agency with regulatory jurisdiction over the production of natural gas. Jurisdictional agency determinations are subject to review by the Commission.

Jurisdictional agencies are authorized to make the determinations with respect to:

(1) new natural gas under section 102(c) of the NGPA;

(2) certain gas from the OCS under section 102(d);

(3) new, onshore production, defined in section 103(c);

(4) high-cost natural gas defined in section 107(c); and

(5) stripper well natural gas defined in section 108(b).

The purpose of Subparts B, C, G, and H, of Part 271, is to reflect the statutory criteria for qualification for the maximum lawful prices for the categories of gas noted above and to establish rules necessary to clarify or implement those provisions. Subpart B of Part 274 of the regulations contains the filing requirements which apply to applications for determinations filed with jurisdictional agencies. Subpart A of Part 274 of the regulations applies to the procedures by which jurisdictional agencies make initial determinations and give notice of these determinations to the Commission. Subpart B of Part 275 of the regulations prescribes the method by which the Commission will review those determinations. Each of these provisions is summarized below.

PART 274 - SUBPART A

Subpart A of Part 274 prescribes procedures by which jurisdictional agencies make determinations pursuant to and in accordance with the NGPA. This subpart provides that the procedures applicable to the determinations by the agency shall be those procedures prescribed by State law to make the determinations under the NGPA or comparable determinations. In addition, this subpart contains a rule concerning the manner in which a jurisdictional agency must notify the Commission that it has made a final determination of eligibility.

Section 274.102 provides that a determination is made once it is "administratively final" before the jurisdictional agency. If, for example, a state agency's decisions are normally subject to rehearing under its usual procedures, the determination is not final until the period for rehearing expires or rehearing is sought and denied.

Section 274.104 provides that a jurisdictional agency must notify the Commission within 15 days after making a determination and prescribes the manner in which the jurisdictional agency shall give the notice. The notice must include: (1) a list of participants in the proceeding and any person who submitted or sought to submit written comments; (2) a statement indicating whether the matter was opposed before the jurisdictional agency; (3) the information set forth in § 275.105 as applied to the determination in question, unless the jurisdictional agency has filed a report with the Commission in accordance with § 274.105; (4) a copy of the application and a copy or description of other material in the record upon which the determination was made; and (5) an affirmative finding that the information described in the applicable filing requirements is contained in the notice.

The final regulations differ from the proposed regulations in three respects. First, the requirement that the agency submit to the Commission a copy of the FERC form submitted to the agency by the applicant has been deleted. The final rule requires the application to be filed whenever an affirmative determination is made, and the FERC form is part of the application. The rule also differs from the proposal by not requiring the jurisdictional agency to submit to the Commission a copy of the complete record; instead the agency must submit the application and either a copy or a description of the materials in the record, in addition to the application, upon which it relied in making the determination. This change was made in response to two comments which indicated that the necessity to file the complete record would be unduly burdensome, requiring the copying and transmittal of large amounts of technical data for a single application. Upon reconsideration, the Commission has determined that it will be able to fulfill its review obligation by looking to the application and if necessary, procuring other materials described as being in the record upon which the agency relied.

The third change is reflected in a new subparagraph (5) in § 274.103. This subparagraph requires that the jurisdictional agency make an affirmative finding that the information required to be filed with an application has been forwarded to the Commission. If some of that information was in the files of the jurisdictional agency, copies of the relevant portions of the files must be forwarded to the Commission as part of the notice.

Several comments requested that the Commission add a provision to protect the confidentiality of material submitted under § 274.104, which material may include trade secrets or other sensitive information. The Commission agrees and, accordingly, has added a provision to protect such material in § 275.206.

Section 274.105 provides an option to the procedures prescribed in § 274.104. If an agency chooses to adopt the § 274.105 option, it may file with the Commission a report in which it undertakes to make the necessary determinations and which includes a description of the procedures which it would follow in making them. The jurisdictional agency would then be relieved of the obligation to describe its procedures in each case.

Two comments requested the Commission to add provisions to Part 274 governing certain aspects of the proceedings before the jurisdictional agencies. One comment suggested that the Commission require the jurisdictional agencies to hold full adjudicatory hearings on delegated determinations and allow gas consuming states to participate as a party in interest to the hearings as of right. The other comment suggested that the Commission adopt procedures allowing distribution companies and state commissions and agencies to intervene and have the rights of full parties in interest in hearings held in gas producing states, and that the Commission's "Rules of Practice and Procedure" be made applicable to the hearings before commissions and agencies in other states. The Commission has rejected these suggestions because it does not believe that it has the statutory authority to determine the nature of the proceedings before the jurisdictional agencies. Section 503(c)(3) of the NGPA states:

> Determinations of a Federal or State agency referred to in subsection (a)(1) shall be made in accordance with the procedures generally applicable to such agency for the making of such determinations or comparable determinations under the provisions of Federal or State law, as the case may be, pursuant to which they exercise their regulatory jurisdiction. The Commission may prescribe the form and content of filings with a Federal or State agency in connection with determinations made under this section.

The Statement of Managers indicates that questions regarding procedures followed by the jurisdictional agencies are to be reviewed directly by the state or federal court having jurisdiction to hear such appeals in accordance with

applicable state or federal law. S. Rep. No. 95-1126, 95th Cong., 2d Sess. 119(1978). Since Congress specifically provided that proceedings before the jurisdictional agencies were to be in accordance with their generally applicable procedures and that review was to be by the courts, the Commission lacks the statutory authority to prescribe the procedures suggested in the comments. In view of the Commission's lack of authority, comments concerning proceedings before jurisdictional agencies should be directed to those agencies.

PART 274 - SUBPART B

Subpart B of Part 274 prescribes the filing requirements which must be met by an applicant to obtain a determination from a jurisdictional agency.

Section 274.201 sets forth general rules applicable to all applications, including persons who may file for a determination, the persons who must sign the filing, and the requirement that an applicant give notice of the filing to purchasers.

A number of comments suggested changes in § 274.201(b) with respect to who may file. Several comments requested that the operator be designated as the responsible person. Other comments stated that designating the operator as the responsible person would be too limiting. Concern over non-operating interests was also expressed.

After consideration of these comments, the Commission determined that this is a matter best left to the jurisdictional agency. Accordingly, the section has been revised to provide that the application may be submitted by that person whom the jurisdictional agency identifies as eligible to make filings.

Comments addressing § 274.201(c) indicated that requiring the signature of a "responsible officer of the

corporation" was too limiting. The Commission agrees and has modified this section to permit a "responsible official of the corporation" to attest to the application. It should also be noted that this section has been modified to delete the attestation requirement.

One comment requested that § 274.201(e), "Notice to Purchasers," be expanded to include notice to all working interest owners. Although the Commission has decided not to expand the notice requirements in this manner, it notes that such a requirement might be imposed by the jurisdictional agency. Also the applicant may want to give such notice as a prudent business practice.

Section 274.201(e), as proposed, required that the applicant provide the purchaser(s) with a copy of the application. Upon further consideration, it has been determined that the purpose of this paragraph can be served by requiring only that the applicant provide the purchaser with a copy of FERC Form No. 121.

One comment requested the addition to the general provisions of a section allowing the filing of simultaneous multiple applications for determinations. Permitting these filings appears to the Commission to be desirable; there is clear legislative history that such filings were contemplated under the NGPA. However, since this matter involves procedures of jurisdictional agencies, whether such filings will be permitted is a matter which is better left to the discretion of such agencies.

One comment suggested that the purchaser should be required to play a larger role in the regulatory scheme by concurring in a producer application for a determination with regard to a sale of at least 1,000,000 Mcf per year. The Commission recognizes the merits of a procedure which would involve the monitoring of applications by purchasers. Although this type of program will not be adopted at this time, purchasers are encouraged to participate in the determination process to the extent permitted by the jurisdictional agency.

Several comments suggested that the Commission recognize the problem of confidentiality which was not addressed in the proposed regulations. The Commission agrees that this problem should be addressed and has included such a regulation in § 275.206. Since this rule was not previously proposed, the Commission is particularly interested in comments on the procedures contained in this rule.

Section 274.202 sets forth filing requirements for a determination that gas qualifies as new natural gas under section 102 of the NGPA. The regulations require an applicant to present evidence substantiating, to the extent practicable, each element of proof required for a determination of eligibility. Section 274.202(c)(1) is typical of other sections in this subpart in that the applicant must file certain specific documents as well as the oath statements. Each applicant filing for a new onshore well determination under § 274.202(c)(1), must file a location plat locating his own well and any other well within the 2.5 mile radius which is producing or has produced natural gas after January 1, 1970. In order to demonstrate that none of these wells is a marker well, an applicant must consult available, relevant records which would indicate whether any of these wells produced in commercial quantities at any time during the period from January 1, 1970, to April 20, 1977. Rather than require an applicant to file all production records with the application, however, the proposal requires the filing of a statement under oath describing the applicant's search of records, and attesting to the fact that none of these wells is a marker well.

Applicants filing under § 274.202(d) for a new onshore reservoir determination must submit geological information which demonstrates that production is from a new onshore reservoir. This information is accompanied by a sworn statement similar to that required by paragraph (c). In all cases, individual agencies may, if they wish, require certified copies of all documents relied upon by the applicant.

Several comments recommended the filing of the OCS lease in lieu of the proposed filing requirements. Acknowledging this recommendation, the Commission has changed the filing requirements to require a copy of the OCS lease or such other identification of the lease as permitted by the jurisdictional agency together with an oath statement by the applicant that the gas is produced from a new OCS lease.

Several comments suggested modification of the diligent search requirement for new onshore wells and new onshore reservoirs. Comments stated that in some instances royalty records do not exist and tax records were not public. Other comments stated that the search should be limited to pertinent records; still others stated that the search of production, severance tax and royalty records should be illustrative and not mandatory. In response to these comments, these requirements have been modified in all sections to require a "diligent search of all records (including but not limited to production, state severance tax, and royalty payment records) which are reasonably available and contain information relevant to the determination of eligibility."

One comment suggested a modification in the "inconsistent information" language of the oath statements required for new onshore wells and new onshore reservoirs. The regulations now require that the applicant state under oath "that applicant has no knowledge of any other information not described in the application which is inconsistent with his conclusion." (§§ 274.202(c)(1) (v)(D) and (c)(2)(vi)(D)).

One comment regarding new onshore reservoirs suggested the addition of surface pressure surveys to the list of geological data which must be consulted if readily available. The regulation now requires in § 274.202(d)(1)(ii)(B), "bottom hole pressure surveys, or surface pressure surveys."

Several comments objected to the task of locating all wells within a 2.5 mile radius on the location plat (§ 274.202(c)(1)(iv)) or identifying all marker wells on a location plat (§ 274.202(c)(2)(iii)). Recognizing that this filing requirement may be unnecessarily burdensome, the regulations now require identification of those wells which are producing or have produced natural gas after January 1, 1970, within the 2.5 mile radius and a specific identification of all marker wells within the 2.5 mile radius.

Section 274.203 sets forth filing requirements for a determination that gas qualifies as a new reservoir on old OCS leases under section 102 of the NGPA. The regulations require the applicant to file geological information to the extent necessary to support such a determination. In addition to the submission of geological information, the applicant must file a statement under oath containing the basis for the conclusion that the gas is produced on an old lease on the OCS from a reservoir not discovered before July 27, 1976. If the date of penetration of the reservoir is prior to July 27, 1976, certain requirements of OCS Order No. 4 must be met in order to qualify for this determination.

Comments similar to those addressed in § 274.202 which requested modification of the diligent search filing requirement and the "inconsistent information" oath statement were filed. The changes noted above have been made.

Section 274.204 sets forth filing requirements for a determination that the well qualifies as a new onshore production well under section 103 of the NGPA. The regulations require the applicant to file, inter alia, the well completion report, a location plat which identifies the subject well and all other wells within that proration unit. In addition, the applicant must file a statement under oath, that the surface drilling of the well was begun on or after February 19, 1977, that the well satisfies well-spacing requirements and was not within an existing proration unit. If the applicant is seeking a determination for a new well drilled in an existing proration unit, the applicant must also demonstrate that the new well is necessary to effectively and efficiently drain a portion of the reservoir covered by that proration unit.

Only comments similar to those addressed in § 274.202 were suggested for this section.

Section 274.205 sets forth filing requirements for a determination that gas qualifies as deep high-cost gas under section 107 of the NGPA. The regulations require the applicant to file, inter alia, the well completion reports, the well logs or well servicing company reports or such other information necessary to substantiate the depth of the well. In addition, the applicant must file a statement under oath that the surface drilling began on or after February 19, 1977 and that the well is completed at the depth of at least 15,000 feet.

Based on a concern for protecting confidential filings, several comments suggested the deletion of well logs as a filing requirement for high-cost gas. The Commission recognizes the importance of protecting proprietary interests and the need for confidentiality. The regulation has been modified to require "well logs, or well servicing reports or such other information which will corroborate the depth of the completion location reported in the well completion report." The final phrase of the oath statement was modified slightly to read, "that he has no knowledge of any other information not described in the application which is inconsistent with his conclusions."

Section 274.206 prescribes the filing requirements for applications for stripper well determinations. To a greater extent than other sections of this subpart, this section requires the submission of actual documents rather than oath statements. In addition to the documents, applicants must submit an affidavit attesting to the well's eligibility.

After reviewing the comments, we believe that § 274.206(a)(6) should be modified. We adopt the comment suggesting that the Commission change this section to provide that an applicant must file the production records for crude oil produced during the 90-day period on which the application is based rather than the 12-month period immediately preceding the date of filing. We believe this change is consistent with section 108 of the NGPA.

Several comments objected to the requirement in § 274.206(b) that pipeline companies monitor the production of natural gas from stripper wells. It was argued that the qualification of wells as strippers is a responsibility of the producers and not the pipelines. However, we find that to require the pipeline purchaser to monitor its purchases of stripper well natural gas is not unduly burdensome. Further, we believe that it is consistent with the obligation owed to their purchasers to insure that all gas purchases are properly priced.

One jurisdictional agency suggested that the Commission should require one-page production decline curves instead of monthly production reports. In those instances where a jurisdictional agency prefers to use a production curve, it may seek Commission approval of this alternative filing requirement under § 274.207.

Section 274.207 entitled "Alternative filing and notice requirements," acknowledges that due to differences in state records, some jurisdictional agencies may want to require other documents than those enumerated in the interim regulations. Under this section, a state agency may propose alternative filing requirements which might replace some or all of the requirements specifically provided in Subpart B. If the Commission concludes that the alternative requirements will satisfy its evidentiary requirements, the Commission may approve the alternative requirements. Upon such approval, applicants for determinations in that jurisdictional agency would file according to the alternative plan rather than under Subpart B. The section has been modified to permit jurisdictional agencies, subject to Commission approval, to provide different documents in their notification to the Commission of determinations from those now required. As jurisdictional agencies and the Commission develop experience under the NGPA, this section will provide needed flexibility.

Several comments suggested that the Commission should formulate alternative filing requirements for small producers to ease the burden of complying with Section 274, Subpart B filing requirements. While the Commission appreciates the concerns of the small producer, a specific regulation addressing small producers is not contemplated. However, the regulations do not prohibit the jurisdictional agency from adopting specific small producer filing requirements under the alternative filing requirements section provided the alternative filings constitute a reliable record upon which determination may be based.

PART 274 - SUBPART C

Subpart C of Part 274 briefly prescribes the procedures by which a jurisdictional agency may execute an agreement to waive its authority to make NGPA determinations. It implements section 503(c)(2) of the NGPA.

In order for a jurisdictional agency to waive its authority, it must enter into an agreement with the Commission. Under § 274.302, an agency may submit a request for waiver to the Commission. Section 274.302 also specifies the contents of such a request and requires an agency to state the reasons and the necessity for a waiver. If the Commission agrees to enter an agreement of waiver, it may do so on terms and conditions agreed to by the Commission and the jurisdictional agency. The provisions of § 274.303 specify the method of revoking or terminating the waiver agreement by the Commission or the jurisdictional agency. Section 274.304 provides that the Commission shall give public notice of all agreements of waiver and any termination or revocation of a waiver.

PART 274 - SUBPART D

Subpart D of Part 274 authorizes delegation to certain state regulatory agencies of the Commission's authority under Part 276 to receive filings under Part 276. Any such delegation is made by agreement with the state agency in accordance with section 501(c) of the NGPA.

PART 274 - SUBPART E

This subpart defines jurisdictional agency, contains a table of agencies by state, defines Federal lands, and provides for recognition of agreements between the United States Geological Survey and state jurisdictional agencies which would permit the state agency to make determinations under Part 274 respecting wells on Federal lands within the state.

PART 275 - SUBPART B

Subpart B of Part 275 prescribes the procedures governing Commission review of determinations by jurisdictional agencies. The regulations are promulgated under the provisions of section 503 of the NGPA and the general rulemaking authority of section 501(a) of the Act.

Section 275.201 provides that upon receipt of the notice of determination from a jurisdictional agency, the Commission will give public notice of the determination in the Federal Register. In addition to identifying the specific proceeding, the notice will indicate that the application and a copy or description of materials relied on by the jurisdictional agency in making the determination is available for inspection in the Commission's Office of Public Information, except to the extent such material is treated as confidential under § 275.206. The final rule is changed from the proposal to reflect the change to § 274.104 which no longer requires the complete record to be submitted by the jurisdictional agency.

Subparagraph (a) of § 275.202 tracks section 503(b)(1) and (2) of the statute in setting forth the standards which govern Commission review. The determination of the jurisdictional agency will become final 45 days after the Commission receives notice of the determination unless within that time the Commission issues a preliminary finding and notice that the determination was not supported by substantial evidence or that there is evidence in the Commission's records which was not before the jurisdictional agency and which is inconsistent with the determination.

One comment suggested that the Commission should delete paragraph (b) of the proposal which provided that the Commission would return determinations to jurisdictional agencies if such determinations were based on applications which did not satisfy applicable requirements. After consideration of this matter, the Commission has decided that a more appropriate procedure is to provide that the 45-day review period will not begin if the Commission notifies the jurisdictional agency that the notice is incomplete in certain respects. This provision is set out in § 275.202(b). This provision accomplishes the same purpose as the proposal and gives the jurisdictional agency an opportunity to perfect its notice to the Commission.

Paragraph (c) of § 275.202 changes the proposal by providing that the Commission will publish notice of a preliminary finding in the Federal Register and will also post the notice in its Office of Public Information. The notice will contain the reasons for the preliminary finding. This provision was added in the final rule in response to comments suggesting that the views of interested persons and state or federal agencies should be allowed subsequent to a preliminary finding.

Paragraph (d) of § 275.202 provides that any state or federal agency, or any interested person may submit written comments with respect to a preliminary finding. The rule further provides that any jurisdictional agency, any state agency, any person who participated in, the proceeding before the jurisdictional agency and any person who has filed a protest may request a conference with the Commission staff, which request will be granted, if timely made. In response to one comment, the final rule has increased the time period within which comments may be filed to 30 days.

As noted above, the changes in procedure were made in response to a comment indicating that interested persons or state agencies may not be able to participate before a jurisdictional agency or be able to prepare a protest to the Commission within 15 days after public notice of a jurisdictional agency determination. Therefore, they might be effectively excluded from participation. The revised procedures provide the greatest opportunity for public involvement possible in the limited time for Commission review. Another comment suggested that participation in proceedings before the Commission be limited to agencies or persons who had participated in proceedings before the jurisdictional agency, or who could show good cause why they did not participate. While the Commission agrees that participation before the jurisdictional agency would be preferable, it cannot guarantee, or provide procedures for such participation. Further, in view of the statutory time constraints, the Commission cannot undertake to make individual findings as to whether the person or agency had good cause for not participating before the jurisdictional agency. Accordingly, the Commission has rejected the suggestion to limit participation in its proceedings.

Section 275.202(e), consistent with sections 503(b)(1)(B), and (b)(2)(B) provides that the Commission will issue a final order within 120 days after issuance of a preliminary finding. While the statute requires a final order only when the Commission reverses or remands a decision, the regulation provides that the Commission will issue such an order in any case in which a protest was filed and a preliminary reversal or remand was issued. The final rule differs from the proposal only to clarify the persons to whom notice will be given.

Under § 275.203 any person may file a protest with the Commission within 15 days after the Commission publishes notice of receipt of a determination by a jurisdictional agency. Any person protesting a determination must indicate whether it is alleged that the determination is not supported by substantial evidence or that there is inconsistent information in the Commission's files. It should be noted that under § 275.203(b)(3), a protestor may submit information for inclusion in the Commission's public records. Accordingly, the data or information on which the Commission may rely in remanding a determination need not have been in the

Commission's records at the time the jurisdictional agency made the determination.

One comment suggested that a provision be added to permit an applicant to respond to protests prior to the preliminary finding. The Commission has not adopted this suggestion because it has determined that to provide for such a response before the preliminary finding is impracticable in view of the short time within which the Commission must make its preliminary finding. The applicant's interests are adequately protected by the procedure permitting comments and conferences after the issuance of the preliminary finding.

Another comment objected to the procedure which allows a protester to submit information for inclusion in the Commission's public record for purposes of supporting a remand of the determination. The Commission has retained this procedure because it believes its procedure should encourage interested persons to submit any relevant information which is likely to result in a correct final determination.

One comment suggested that the Commission require protests to be filed under oath. The Commission has not implemented this suggestion because it does not feel that such an oath is necessary. If, after gaining some experience in administering the Act, the Commission feels that such an oath is necessary, it will amend its regulations to include the suggested provision.

Under section 503(d), final determinations are binding unless based on an untrue statement of fact, or based on a record from which a statement of material fact was omitted. Section 275.205 of the regulations sets forth a procedure for reopening determinations on those grounds. The Commission may, at any time, on its own motion or in response to a petition, reopen a determination if it appears that the necessary grounds exist.

If the Commission does reopen a determination, it will give notice to the jurisdictional agency involved as well as to all persons who participated in the prior proceeding. Within 150 days of the Commission order reopening a determination the Commission will issue a final order after giving all persons who received notice an opportunity to express their views. If the Commission finds that the requisite grounds exist, it will vacate the determination and order remedies, including refunds, as it deems appropriate.

Confidentiality. Section 275.206(a) provides that the Commission will accord confidential treatment to any information submitted to the Commission by a jurisdictional agency under § 274.104, if the agency protected the information as confidential and if the grounds for confidential treatment fall within one of the nine exemptions of the Freedom of Information Act (5 U.S.C. 552(b)). Paragraph (b) provides that if the Commission receives a request for disclosure of the information protected as confidential under paragraph (a), it will determine whether the information is exempt from public disclosure under the Freedom of Information Act. If the information is determined not to be exempt, it will be released to the public. If it is determined to be exempt, the information will not be released unless the Commission determines that its conduct of the proceedings requires the disclosure of the information to the public or to particular parties, subject to conditions prescribed by the Commission. The person who submitted the information will be given at least 10 days notice before the information is made public. This section of the regulations was not in the proposed rules. Several comments suggested that the Commission add a provision to protect the confidentiality of material submitted by the applicant or contained in the materials submitted by the jurisdictional agency to the Commission, since the release of such information could inflict substantial competitive harm upon the applicant. The Commission agrees with the comments and accordingly has added this section to the final rules.

PART 276 - SUBPART A

Subpart A of Part 276 sets forth reporting requirements applicable to first sales of natural gas sold under existing intrastate contracts and intrastate rollover contracts, as well as first sales of other categories of natural gas (Subparts E, F, and I of Part 271).

For each first sale under these subparts of Part 271, the seller is required to report certain information. If the purchaser of gas under section 105 and 106(b) of the NGPA is a pipeline, the purchaser must file certain reports. Finally, in some instances, sellers of less than 10,000 MMcf of natural gas per year may elect to make oath filings instead of detailed reports.

Under § 276.102 a seller of natural gas under an existing intrastate contract must file an annual report setting forth detailed contract information as well as an oath filing that the information in the report is true, and that sales in the reporting period comply with the NGPA and Subpart E of Part 271. Successive annual reports need not restate previously reported information. The seller must also undertake to retain all records containing information reported.

If the sale is to an interstate or intrastate pipeline, the pipeline, rather than the seller, is responsible for filing the contract information, as well as an oath statement attesting to the accuracy of the information so reported. If a pipeline purchaser makes the principal filing, the seller must still file a statement under oath that the sale complies with the NGPA and Subpart E of Part 271, and that the seller undertakes to retain records which reflect the detailed contract information required to be reported by the purchasing and reporting pipeline.

Reports required to be filed with respect to sales under intrastate rollover contracts are essentially the same as for sales under existing intrastate contracts, with appropriate modifications. These reporting requirements are set forth in § 276.103.

The annual report requirements with respect to sales under Subpart I of Part 271 are set forth in § 276.104. The report must be filed by the seller in all instances and must contain detailed information with respect to the sale. The seller is also required to make an oath statement that the gas does not qualify under any subpart of Part 271 which provides a maximum lawful price lower than that provided under Subpart I, and that, if the gas was committed or dedicated to interstate commerce, a notice of rate change has been filed pursuant to § 154.94. The oath filing must also contain a statement regarding compliance with the NGPA and the requirements of Subpart I and must attest to the truth of the information reported.

Sellers who sell less than 10,000 MMcf per year may elect to comply with reduced reporting requirements with respect to sales under Subparts E and F of Part 271 to purchasers other than a pipeline. Instead of the detailed information otherwise required, these sellers may file an oath statement attesting to compliance with the NGPA and the applicable regulations. Such sellers must also undertake to retain books and records containing the requisite information.

As issued, the interim regulations in this subpart reflect several substantive changes. Sections 276.102(b) and 276.103(b) have been amended to impose two new reporting requirements. The requirement that the highest price per MMBtu charged and collected during the reporting period be reported for sales under Subparts E and F of Part 271 has been added in order to enable the Commission to conduct a more meaningful review of the reports filed. A requirement that all contract provisions be identified which were executed during the reporting period and which obligate a new purchaser to incur increased production-related costs has been added to correspond to revisions made in §§ 271.505 and 271.604. In addition, all persons making first sales under sections 105, 106(b), and 109 of the NGPA must retain records containing the information relevant to those sales under § 276.107.

One comment on this subpart of the regulations challenged the statutory sufficiency of an audit procedure, alleging that the Commission must make separate determinations regarding each seller's ability to charge those maximum lawful prices prescribed under sections 105, 106(b), and 109(a)(1) and (3) of the NGPA. However, the statute does not specifically provide for nor require such determinations. Given the administrative burdens attendent on making such determinations, the delay which such a determination procedure would cause, and the efficacy of the current reporting system in providing the information necessary for auditing to ensure compliance with the pricing limitations in the statute, the Commission can foresee no valid reason for instituting such a determination procedure.

Correspondingly, the Commission rejects the suggestion by a second commentor that all intrastate producers be relieved of the burdens imposed by such reporting requirements for the next several years, and be required, instead, merely to retain the relevant records for that period until the need for such data is demonstrated through the

Commission's experience in enforcing the NGPA. The Commission considers the auditing process to be essential to ensuring that those persons making first sales comply with the new pricing system under the NGPA and Part 271 and emphasizes that, because compliance with the statute is an essential element to its workability, the pricing provisions must be enforced as soon as possible.

Another comment suggested that purchasers rather than sellers be required to fulfill all reporting requirements imposed by this subpart. The Commission has already implemented such a policy, where it deems it appropriate, in order to assist the Commission in enforcing compliance with sections 105 and 106(b) of the NGPA. The Commission concludes that pipelines are the appropriate entities for filing reports concerning those sales. As purchasers of the natural gas, the pipelines have an immediate economic interest in determining that a lawful price is charged. Accordingly, they should closely scrutinize any price charged by a seller in order to determine whether that price is consistent with the maximum lawful prices permitted by the NGPA and Part 271. Since the pipelines have the economic interest, the Commission believes it will receive the most accurate information from their filings and that such accuracy will more adequately ensure that maximum lawful prices are not exceeded by sellers. By requiring pipeline to make filings under this subpart, the Commission has also more equally distributed the burden of making filings under the NGPA. Because the information required in this subpart will have been compiled incident to the pipeline's own audits, the burdens imposed should be limited.

Such filings by pipelines are appropriate from a legal as well as a policy perspective. Section 508(b) of the NGPA provides that:

> [i]n order to obtain information for the purposes of carrying out its functions under this Act, the Commission shall have the same authority as is vested in the Secretary [of Energy] under section 301(a) of the Department of Energy Organization Act with respect to the exercise of authority under section 11(b) of the Energy Supply and Environmental Coordination Act of 1974 and sections 13(b), (c), and (d) of the Federal Energy Administration Act of 1974.

The Congressional grant of authority in section 508(b) of the NGPA is broad. Section 301(a) of the Department of Energy Organization Act vests in the Secretary of Energy all of the functions vested by law in the Administrator of the Federal Energy Administration or the Federal Energy Administration; the Administrator of the Energy Research and Development Administration or the Energy Research and Development Administration; and the functions vested by law in officers and components of either such Administration. Thus, the Commission may exercise these same powers in order to obtain information for the purposes of carrying out its functions under the NGPA. One such function is enforcement under section 504 of the NGPA of the pricing rules.

The information gathering powers enumerated in § 508(b) permit the Commission to carry out this function by requiring filings by pipelines. Section 11(b)(1)(A) of the Energy Supply and Environmental Coordination Act of 1974 permits the Commission "to require by rule, any person who is engaged in the production, processing, refining, transportation by pipeline or distribution (at other than the retail level) of energy resources to submit reports. . . ." [Emphasis supplied] Moreover, section 13(c) of the Federal Energy Administration Act of 1974 likewise provides for certain information gathering powers:

> [t]he Administrator [i.e., the Commission] may require, by general or special orders, any person engaged in any phase of energy supply or major energy consumption to file with the Administrator in such form as he may prescribe, reports or answers in writing

> to such specific questions, surveys, or questionnaires as may be necessary to enable the Administrator to carry out his functions under the Act. Such reports and answers shall be made under oath, or otherwise, as the Administrator may prescribe, and shall be filed with the Administrator within such reasonable period as he may prescribe. [Emphasis supplied]

The Commission has decided to exercise its information gathering powers in a manner that requires pipeline companies to submit the reports required by Subpart A of Part 276 of the regulations.

Another comment suggested that the category of sellers exempted from certain filing requirements under §§ 276.102 and 276.103 be revised to coincide with the definition of small producers in § 271.402(b)(10). That provision has now been revised, however, the use of the definition in paragraph (b)(10) would not cover all sellers intended to be included in the exemption. It would eliminate all sellers who were not also producers but who would qualify as having made a first sale subject to the pricing provisions of the NGPA. The Commission intends to establish in this regulation a simple volumetric limitation based on which sellers may be exempted from providing detailed contract information pursuant to this subpart. The purpose of the exemption is substantially different from the pricing considerations which were imposed by the NGA and which underlie the provisions of § 271.402(a). The definition in § 271.402(b)(9) only incidentally concerns filing requirements and was intended to implement under the NGPA a pricing system established under the NGA.

PART 284

Part 284 implements sections 311(a) and 312 of the NGPA. Subparts A and B govern transportation of natural gas by interstate and intrastate pipelines. Subpart D establishes requirements governing the assignment of producer contracts by intrastate pipelines. The Commission has reserved Subpart C which, when implemented, will apply to intrastate pipeline sales under section 311(b) of the NGPA.

Special mention should be made of the Commission's decision to reserve Subpart C at this stage. A number of comments were directed to the proposed implementation of section 311(b) in response to the Commission's notice of proposed rulemaking on November 13, 1978. These comments suggest that substantial revision of the proposal will be required. Thus, the Commission intends in the near future to issue a revised notice of proposed rulemaking. However, there was inadequate time to consider and deliberate on the revisions suggested so as to allow the Commission to issue the revised proposal at this time. It remains the Commission's intention, nonetheless, to implement section 311(b) effective March 1, 1979. In the interim, intrastate pipeline sales will be governed under the emergency program established under the Natural Gas Act. Of course, assignments by intrastate pipelines may be made beginning on December 1, 1978, pursuant to the provisions of Subpart D which implements section 312 of the NGPA.

PART 284 - SUBPART A

This subpart governs the transportation of natural gas by interstate pipelines on behalf of intrastate pipelines and local distribution companies pursuant to the terms of section 311(a)(1) of the NGPA. Two mechanisms are established. The first is self-executing and allows transportation arrangements to be entered into without necessity of prior Commission approval for periods not in excess of two years. The Commission has also added a provision that would permit transportation arrangements for fixed periods in excess of two years. In this latter case, however, application must be made to the Commission and prior approval obtained. The Commission believes that it is appropriate to review and evaluate long-term transportation arrangements in view of the potential impacts of such arrangements on the operation of on an interstate pipeline's system. Arrangements for fixed terms in in excess of two years may involve significant investments in the construction and operation of facilities. This consideration also supports the approach taken here by the Commission.

Several commentors suggested that the Commission should remove the two-year limitation and rely instead on its ability to impose terms and conditions which would have the effect of terminating an arrangement if the Commission concluded that a continuance of the arrangement was not in the public interest. We do not believe that is a sensible regulatory approach to this problem. As noted above, long-term transportation arrangements may be expected to contribute to the need for future investment which will require amortization over a period of years and may impose a burden upon all customers of the pipeline. Serious questions of equity and practicality would attend any attempt to abruptly terminate an arrangement which had been entered into in contemplation of its continuance for a period sufficiently long to justify the investment. Moreover, we doubt that parties would enter into long-term arrangements if they were subject to the jeopardy that the Commission may, on its own motion and at any time, terminate the arrangement.

The Commission wishes to emphasize that the two-year limitation applicable to transportation arrangements which may be entered into without prior Commission approval should not be read as indicating a predisposition on the part of the Commission against longer-term arrangements. Indeed, the Commission is well aware that the NGPA seeks to strike down the jurisdictional barriers which have precluded interstate and intrastate pipelines from taking advantage of the most economic and efficient means of transporting natural gas. Sections 311(a)(1) and 311(a)(2) provide the Commission with important new authorities designed to achieve a national transportation system with its attendant economies and efficiencies. On the other hand, transportation arrangements for fixed periods greater than two years contemplate service periods which may so significantly affect a pipeline's system operation as to require prior Commission scrutiny and approval. It is for these reasons that the Commission has chosen the two-pronged mechanism contained in Subpart A and Subpart B of Part 284.

Other than the addition of the application procedure for transportation arrangements in excess of two years, only minor revisions have been made to the proposed regulation. The most significant is the addition of provisions to § 284.103 which would permit an interstate pipeline to retain revenues in excess of 1 cent per Mcf if it is able to demonstrate that the amounts retained represent actual out-of-pocket expenses in excess of the 1 cent allowance. The Commission notes, parenthetically, that the 1 cent per Mcf allowance for out-of-pocket costs derives from the Commission's experience in a number of individual cases under the Natural Gas Act which evidenced that the 1.0 cent per Mcf reasonably represented the level of out-of-pocket costs normally incurred by interstate pipelines in rendering transportation service. But, we recognize that individual transportation arrangements occurring under Subpart A may involve the incurrence of out-of-pocket expenses greater than 1.0 cent per Mcf. Accordingly, the Commission will permit an allowance in excess of 1 cent per Mcf provided the pipeline is able to substantiate greater out-of-pocket cost.

Section 284.104(c) has been revised, in response to comments, to provide that the terms and conditions which the Commission may impose by rule or order, under the section, shall be prospective. Section 284.106(d) has been revised to clarify that the final report is required only after the termination of an extension where one has been entered into in accordance with § 284.105.

Subpart A provides that interstate pipelines engaging in transactions under this subpart may recover the costs of providing the service including the retention of any revenues where such transportation transactions have been reflected in the pipeline company's rates either through the crediting of revenues or the inclusion of the transportation volumes in billing determinants.

PART 284 - SUBPART B

This subpart governs the transportation of natural gas by intrastate pipelines on behalf of interstate pipelines and local distribution companies served by interstate pipelines under section 311(a)(2) of the NGPA. Sections 284.122 and 284.127 have been revised to conform to §§ 284.102 and 284.107 of Subpart A. The considerations which prompted the Commission's decision under Subpart A apply equally here. Parity of treatment of interstate and intrastate pipelines under similar statutory provisions also support this decision.

Section 284.123(b)(1)(i) has been revised to provide for rates which are based on recovery of all costs which may be associated with the transportation function. Section 284.123(b)(2) has been added to govern those cases where the intrastate pipelines' transportation rates are not subject to the jurisdiction of an "appropriate state regulatory agency." Section 284.123(d) provides that transportation rates computed in accordance with § 284.123(b)(1) are presumed to be fair and equitable and not in excess of the rates and charges which interstate pipelines would be permitted to charge for providing similar transportation service. This is consistent with and conforms to statutory language in section 311(a)(2) of the NGPA. Moreover, the Commission presumes that all revenues associated with those transportation transactions engaged in by regulated intrastate pipelines have been, or will be, considered by the appropriate state regulatory authority in establishing rates to be charged. This treatment would be consistent with treatment of interstate pipelines by this Commission.

Section 284.124(a) has been added; and § 284.124(c) has been revised to conform to the corresponding section in Subpart A. The initial report required by § 284.126(a) will be filed with the "appropriate state regulatory agency." This term which is also used in § 284.123 is defined in § 284.128. The filing of the initial report with the "appropriate state regulatory agency" is necessary to implement the provisions of § 284.123(c).

The Commission wishes to call special attention to certain features of the regulation under Subpart B. The provisions of § 284.123 governing the rates and charges by intrastate pipelines for transportation arrangements under this subpart have been revised to permit an intrastate pipeline to elect to base its rates upon the methodology and cost used in determining the allowance permitted by an appropriate state regulatory agency for city-gate service. The Commission understands from a number of comments received that in some cases, state regulatory agencies exercise cost of service type regulation at the distribution company level permitting an allowance for city-gate service rendered by intrastate pipelines. Thus, commentors have pointed out, the intrastate pipeline is effectively regulated albeit the state regulatory agency does not directly accept for filing and pass on "rates and charges for transportation" as such. Also, the Commission has modified § 284.123 to specify that in any case where an intrastate pipeline does not elect to base its rates upon the methodology and cost formulae contained in paragraph (b)(1) or where the intrastate pipeline is not regulated directly or indirectly on a cost-of-service basis, the pipeline may file proposed rates and charges with the Commission supported by information showing that the proposed rates and charges are fair and equitable. Upon filing, the intrastate pipeline may commence the transportation service and charge the proposed rates subject to refund. It need not await approval or further action of the Commission. Paragraph (b)(2) also provides, however, that the Commission may order refunds of any amounts which it may, through subsequent procedures, determine to have been charged in excess of rates and charges which interstate pipelines would be permitted to charge for similar service or amounts which it determined to be in excess of those which have been shown to be fair and equitable.

A number of commentors were concerned that the Commission had not allowed an opportunity for the intrastate pipeline to earn a reasonable profit as required by section 311 of the NGPA. If the intrastate pipeline files its proposed rates and charges pursuant to § 284.123(b)(2), the intrastate pipeline, of course, would include a reasonable profit within its proposed rates. If, on the other hand, the intrastate pipeline elects the alternative procedures contained in § 284.123(b)(1), the reasonable profit is built into the formulae contained in clauses (i) and (ii). In other words, the intrastate pipeline is permitted the same opportunity for profit as is permitted by the appropriate state regulatory agency under the methodologies used in designing rates or in determining the allowance referred to in those clauses.

As set forth in § 284.123(d), the rate charged by an intrastate pipeline which elects the procedures under paragraph (b)(1)(i) or (ii) is presumed to be fair and equitable and not in excess of the rates and charges which interstate pipelines would be permitted to charge for providing similar service. The Commission has had considerable difficulty in determining a practical method for applying the statutory limitation on rates contained in section 311(a)(2). At this time, we have attempted to resolve this problem by presuming that if an intrastate pipeline is regulated on a cost-of-service basis, it would not be permitted to charge a rate which is greater than the rate which would be allowed an interstate pipeline similarly regulated on a cost-of-service basis. The Commission recognizes, however, that no two pipelines are alike and that rate schedules of interstate pipelines reflect the particular characteristics of the pipeline and are tied to the size and length of the line, the load factor of its operation, the location and nature of its supply and the characteristics of its markets.

It is for these reasons that the Commission rejected suggestions made by some commentors that the Commission permit intrastate pipelines to merely select a rate schedule on file with the Commission governing transportation service by interstate pipelines. We are also in doubt as to how we would measure comparability of service in the case of pipelines which have substantially different investments, operations and costs. While we are not prepared to conclude that an approach of this nature cannot be fashioned, we must admit that we are unable to do so at this time. For this reason, the Commission invites interested parties to address this question in the extended comment period on the interim regulations.

PART 284 - SUBPART D

Subpart D implements section 312 of the NGPA which governs assignments of contractual rights to receive surplus natural gas by intrastate pipelines to interstate pipelines and local distribution companies. Rates charged for transportation services in connection with assignments are determined in accordance with Subpart B. Changes made in that subpart have been reflected in similar provisions of § 284.164(a) and §§ 284.165(a)(5) and (e)(1)(v). The report requirements have also been reduced in response to comments received. No other significant changes have been made in this subpart.

PARTS 2 and 157

The Commission's existing regulations promulgated under the Natural Gas Act exempt from the certificate requirements under section 7 of that Act certain emergency transactions. These provisions, contained in 18 C.F.R. §§ 2.68, 157.22 and 157.29, permit the transportation and sale of natural gas in interstate commerce without prior certificate authorization from the Commission. Under these provisions, emergency supplies of natural gas have been obtained in substantial quantities in past winter heating periods and during times of summer storage fill at market prices in excess of otherwise applicable national or area rates governing jurisdictional sales.

It is generally acknowledged that these exemptions for emergency transactions have allowed interstate pipelines, distribution companies and others dependent upon interstate pipeline supplies to avoid, or at least alleviate, the consequences of severe supply shortages of natural gas in the interstate market. Nonetheless, a number of criticisms have been leveled at the existing program suggesting that it was subject to abuse and required administrative tightening.

Accordingly, on April 7, 1978, the Commission determined to review the current emergency program and issued a Request for Comments inviting interested persons to submit their views on the program and to offer suggestions for change. After the comments were reviewed and analyzed, the Commission issued a Notice of Proposed Rulemaking on August 14, 1978, and again requested comments. That proposal would have substantially changed the provisions of the Commission's current regulations applicable to emergency transactions.

Comments were received from parties representing a wide range of interests, including independent and associate producers, interstate and intrastate pipelines, distribution companies, industrial consumers and the public.

The August 14, 1978, proposal was described in substantial detail in the Notice of Proposed Rulemaking and no recapitulation or further elaboration will be attempted here. It is sufficient to note only that it would have imposed stricter requirements for participation in emergency transactions and would have added additional reporting requirements to allow the Commission to monitor more closely the activities of emergency purchasers and sellers.

Prior to final action by this Commission on the August 14, 1978, proposal, the Congress passed and the President signed into law the NGPA, which changed much of the statutory authority on which the proposed rulemaking had been based and established new congressional directives and policies governing the sale and transportation of natural gas. For this reason, the Commission determined on November 13, 1978, to publish a revised Notice of Proposed Rulemaking more consonant with the requirements and policies of the NGPA. Comments were to be submitted no later than November 20, 1978. The Commission determined that good cause existed to dispense with the full 30 day notice and comment period, inasmuch as the winter heating season had already begun and because the NGPA was to take effect on December 1 -- one month into the heating season.

Practical considerations preclude the Commission from attempting to restate or discuss the comments received since November 13, 1978, in the detail which in other circumstances would be appropriate. The Commission advises, however, that it has read and considered the comments received and made revisions that it considers appropriate and practical given the exigencies of the moment.

Because emergency transactions under the NGA have been overtaken by passage of the NGPA on November 9, 1978, we have determined to promulgate the revised regulations applicable to emergency transactions as interim regulations to be effective December 1, 1978. Accordingly, the revised regulations under the NGA applicable to emergency transactions are to be considered together with the implementing regulations under the NGPA and may be subject to further revision as the Commission may find appropriate after the extended comment period.

Revised Interim Regulations

The interim emergency regulations prescribed herein leave the current emergency program largely intact. The

Commission acknowledges that there are deficiencies in the program which would require correction if it were to continue as a permanent feature of the Commission's regulations. However, that is not to be the case. Rather the Commission intends to continue the emergency interim regulations in their present form only through the current winter heating season.

The Commission intends to substantially revise and limit tne applicability of the emergency program following the current winter heating season. We did not, therefore, consider it wise public policy to attempt major revisions in a program which is to last for only a few additional months. Moreover, recognizing that we are already in the midst of the current heating season, it did not appear reasonable to risk the disruption and uncertainty as would attend a significant revision of the prior existing program.

Some further comment on the proposed duration of the emergency program prescribed herein is appropriate. As previously announced, the Commission intends to implement section 311(b) of the NGPA governing sales by intrastate pipelines effective March 1, 1979. Although not included in this stage of implementing regulations, the Commission intends in the near future to issue a revised notice of proposed rulemaking under Subpart C of Part 284 which will reflect changes in the original proposal.

In the future, therefore, intrastate pipeline sales and assignments, as well as transportation arrangements between and among inter- and intrastate pipelines and local distribution companies are to be governed by the NGPA regulations contained in Part 284.

Effective December 1, 1978, all first sales by natural gas producers are subject to maximum lawful prices and other aspects of the Commission's regulations implementing the NGPA. Moreover, under the NGPA it is no longer necessary for producers to obtain certificates under section 7 of the NGA to commence sales in the interstate market, provided the natural gas was not previously committed or dedicated to interstate commerce. This is so whether producer sales are entered into for emergency purchases or otherwise.

Thus, an exemption from section 7 of the NGA is no longer required or appropriate for producer sales of natural gas not previously committed or dedicated to interstate markets. Accordingly, we have revised our existing regulations to remove those features applicable to producer sales.

Inasmuch as Part 284 is scheduled for full implementation on March 1, 1979, and because producer sales are now governed under the NGPA and not the NGA, the question occurs whether there is any continued need or justification for an emergency program under the NGA after the conclusion of this winter's heating season. The Commission specifically invites comments on this question. At the very least, it would seem that the emergency program, if it is to be continued at all, should be limited to circumstances involving a sudden unanticipated loss of supply or situations in which immediate action is required for protection of life and health or the maintenance of physical property. The Commission would benefit from whatever guidance or suggestion is provided on this subject.

Brief Summary of Emergency Interim Regulations

Sections 2.68, 157.22 and 157.29 of the Commission's current regulations are preserved only to the extent that they apply to existing emergency transactions. Accordingly, the current regulations are to continue in effect and remain applicable to contracts executed before November 9, 1978, in the case of a first sale governed by the NGPA (which will include all producer sales), or before December 1, 1978, in any other case (including sales by intrastate pipelines whose sales are generally not considered first sales governed by the NGPA). The emergency interim regulations also add to the Commission's existing regulations under the NGA a new Subpart C which contains §§ 157.45 through 157.52.

Section 157.45 defines the purpose of new Subpart C and sets out the relationship of this subpart to other parts of the implementing regulations under the NGPA.

Section 157.46 contains definitions which establish the parameters of eligility for the exemption from section 7 of emergency transactions. The definition of emergency has been revised from the November 13 proposal in a number of respects. Specifically the definition has been expanded to make clear that an emergency includes a sudden unanticipated loss of supply or increase in demand. An emergency qualifying under this section would also include situations where additional supplies are necessary to maintain deliverability from storage, or to replenish storage volumes in order to alleviate curtailment. Also, persons described in section 1(c) of the NGA have been included as qualified sellers and purchasers. This responds to a number of comments which suggested the inclusion of so-called Hinshaw pipelines under the program.

In addition, the Commission has defined a "sale of emergency natural gas" to include an exchange of natural gas to alleviate an emergency, provided the volumes exchanged are paid back within 180 days after the termination of deliveries of emergency natural gas. The 180-day pay-back rule is designed to assure that the parties to the exchange are made whole prior to the commencement of the next winter heating season. The Commission, in addition, wishes to make clear that the emergency program contemplates the rendering of emergency storage service by local distribution companies as was permitted under § 2.68 of the Commission's Rules.

A number of comments expressed concern that the Commission may take action under its authority in section 315 of the NGPA to specify a minimum contract duration in such a manner as to disrupt the emergency program. The Commission advises that, although it intends to act in the near future to implement section 315, any such specification of a minimum contract duration will operate prospectively only. Moreover, the Commission will give special consideration to the need to provide an exception to any minimum contract duration requirement for emergency transactions which by their very nature contemplate transactions of brief duration.

Section 157.47 contains the specific exemptions from certificate requirements under section 7 of the NGA. Only minor technical changes in this language have been made. **Transportation by an interstate pipeline for another interstate** pipeline or for a direct assignee is specifically exempted. Transportation by an interstate pipeline for a local distribution company or a person described in section 1(c) of the NGA is governed by Subpart A of Part 284. In this regard, the Commission should note parenthetically that although Hinshaw pipelines are not expressly governed by Subpart A of Part 284, the definition of local distribution companies under the NGPA specifically includes such persons.

The Commission wishes to call special attention to paragraph (c) of § 157.47. Under its terms, the Commission seeks to make abundantly clear that the Commission's jurisdiction under the NGA does not vest with respect to any transaction or person participating in an emergency transaction except to the extent provided in the emergency regulations themselves. Several comments expressed concerned that provisions in existing producer contracts which preclude intrastate pipelines from reselling natural gas in interstate commerce or commingling natural gas in interstate commerce could operate to prevent intrastate pipelines from fully participating under the emergency program. This should no longer be a matter of concern. Those provisions contained in producer contracts were apparently designed to guard against a producer's becoming unwillingly and unknowingly subject to the cost-based rate regulation of the NGA. Passage of the NGPA coupled with the limited vesting of Commission jurisdiction under paragraph (c) of § 157.47 should obviate those concerns.

Section 157.48 contains terms and conditions applicable to emergency transactions. The section has been revised to delete or modify language previously proposed in the August 14, 1978, Notice of Proposed Rulemaking. The revisions and deletions were considered appropriate in light of the interim character of the revised emergency program. In response to comments, this section has been revised to clarify its scope and applicability and to include a provision which places on the person for whom the emergency natural gas is acquired and transported, responsibility to provide volumes for compressor station fuel and line losses.

Section 157.49 establishes requirements which govern the rates for emergency transactions. No significant change has been made in the language. The Commission has determined to keep the presumption of prudence provided at paragraph (b) in cases where the purchased gas cost for emergency natural gas supplies does not exceed the maximum lawful price specified in § 271.202 of Subchapter H applicable to "new gas".

The Commission wishes to emphasize that this is a rebuttable presumption of prudence and is not intended to operate as a floor, as some comments suggested. Moreover, nothing in this section will operate to preclude an interstate pipeline from availing itself of the opportunity to establish that a rate in excess of the new natural gas price was prudent in the circumstances.

The Commission has significantly revised the treatment of revenues contained in § 157.50. Under its terms the interstate pipeline would not be required to credit revenues if its actual out-of-pocket expenses exceed the one cent per Mcf allowance or if the retention of revenues did not provide double recovery. Various formulas are contained in paragraphs (b), (c), (d) and (e) of this section to carry out this intent.

Section 157.51 contains reporting requirements for emergency requirements for emergency transactions. The Commission has revised the quarterly report requirement to limit it to calendar quarters occurring in 1979. Sections 157.52, regarding a waiver of requirements for emergency transactions, and 157.53, relating to certain exemptions for drilling, testing or purging of pipeline facilities are prescribed without revision.

III. PUBLIC PROCEDURE

Subchapters H and I of Title 18 were published in the Federal Register as a notice of proposed rulemaking at 43 FR 53270 on November 15, 1978. That proposal included the following description of the procedures the Commission had applied and would apply to the promulgation of final regulations implementing the Natural Gas Policy Act:

> Although the NGPA was not enacted until November 9, 1978, most of its provisions become effective on December 1, 1978. On that date, persons affected by the Act, including a large portion of the natural gas industry not previously regulated by the Federal govern-

ment, will be subject to a comprehensive and complex new regulatory structure. For reasons set out more fully below, regulations implementing the Act must be effective on December 1, 1978, both for guidance to those regulated and to insure compliance with the new law.

When it became apparent that the period between final enactment of the law and its effective date would not provide sufficient time for the normal rulemaking procedures, the Commission established the following schedule and procedures.

The Commission has been meeting in public session since November 1, 1978, in order to discuss regulations drafted by the staff to implement the NGPA. Prior to the first meeting, the Commission made copies of the various proposals under consideration available to the public. As successive drafts were completed, these too were released prior to Commission discussion. During all of this period, certain members of the Commission staff were publicly designated as contact persons to answer legal and technical questions concerning the implementation of the Act.

The Commission intends to promulgate interim regulations on November 27, 1978. The interim regulations will be effective on December 1. A 60-day comment period will be afforded with respect to the interim regulations and public hearings will be held. The interim regulations will, after the 60-day period and after all views received since November 1, 1978, have been considered, be modified to the extent such comments and the Commission's experience under the interim regulations indicate the modification is appropriate.

The proposal published today provides for a comment period ending on November 20. The Commission is aware that in view of the significance and complexity of these regulations, comments will be extensive. To the extent possible, comments received before November 20 will be reviewed and appropriate changes incorporated into the interim regulations. As stated above, all comments will be retained and considered together with the additional comments received during the 60-day period afforded for comments on the interim regulations. The Commission believes that to the extent practicable, the procedures being followed with respect to these regulations are those best designed to insure maximum public participation prior to the time when the interim regulations must be effective.

In establishing this notice and comment procedure, the Commission has considered a number of factors. Most important, as stated above, is the fact that most of the Act's provisions become effective on December 1, 1978, including provisions establishing maximum lawful prices applicable to first sales of natural gas delivered after November 30, 1978. Some of the prices which may be charged for natural gas deliveries under the Act are established by reference to existing prices. For other categories, pricing determinations must be made by State or Federal agencies with regulatory authority over the production of natural gas. Unless the interim regulations are available on December 1, 1978, members of the public whose sales are governed by provisions of the Act will not be able to ascertain the applicable maximum lawful price governing their sales of natural gas. Indeed, some sellers and transporters of natural gas could unknowingly be in technical violation of the law. Purchasers may be uncertain whether prices requested exceed the prices permitted under the law. Similarly, agencies which must make determinations with respect to eligibility for prices established by the Act must be made aware of Commission requirements applicable to these determinations, including the manner in which the Commission will review such determinations.

After consideration of the problems associated with any delay in promulgating implementing regulations, the Commission has reached the conclusion that because the regulations must be effective by December 1, 1978, good cause exists to limit as described above notice and public procedure on this proposal. Full notice and public procedure on the proposal at this time, which as a practical matter would result in a delay of the effective date of the regulations beyond the effective date of the NGPA, are impractical and contrary to the public interest. It should be emphasized that all of the procedures described above will provide the fullest possible opportunity for public participation during the entire process leading to the promulgation of final regulations.

CONSIDERATION OF COMMENTS

A substantial number of written comments have been received in response to the notice of proposed rulemaking. In addition, the staff met informally, prior to the close of the comment period, with representatives of state agencies, consumer groups, and the industries affected by the proposed regulations.

A notice, describing these meetings and inviting any interested person to meet informally with designated members of the Commission staff was issued on November 17, 1978. Minutes of these informal meetings, together with any written materials presented at these meetings, have been included in the public file. All comments received by the Commission by November 20, 1978, and to the extent possible, comments received after that date, have been considered. In the limited time available to the Commission and its staff, changes in the regulations have been made. The major changes are noted in Section II of this preamble. The preamble also discusses a number of suggestions made in the comments which have not been incorporated into these regulations.

Because of the time limitation, some changes have been made, generally of a minor nature which are not discussed in the preamble, and the reasons for not adopting some suggestions are not mentioned. To the extent possible, significant changes have been explained. The Commission wishes to emphasize that all comments will be retained and reconsidered with comments received as a result of this publication. Accordingly, suggested changes, deletions or additions, not adopted by the Commission in these rules, will, in light of additional information received in the next 60 days, be re-examined and possibly adopted as amendments to the interim regulations.

ADDITIONAL COMMENTS

In accordance with the procedures described below, the Commission solicits comments on all aspects of these interim regulations. It should be emphasized that the Commission intends to review the regulations in their entirety and make whatever changes it deems appropriate based on the comments already received, additional written comments, the views expressed in public hearings, and experiences under the regulations during the next 60 days.

Interested persons are invited to submit written comments on the regulations to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D. C. 20426. Comments should reference Docket No. RM79-3 on the outside of the envelope and on all documents submitted to the Commission. To assist the Commission, it is requested that comments identify the section or subpart addressed, state whether the comments involve technical, legal, or policy matters, and if alternative approaches are suggested, provide proposed implementing language to the extent practicable.

Fifteen copies should be submitted. All comments and related information received by the Commission by January 31, 1979, will be considered prior to promulgation of revisions or amendments to these regulations.

PUBLIC HEARINGS

The Commission intends to hold a series of public hearings on these interim regulations, as required by section 502(b) of the NGPA. For the reasons stated above, however, the Commission finds that it is impracticable to provide an opportunity for oral presentation of data, views and arguments prior to the effective date of the regulations, and waives for 45 days the requirement of prior hearings under section 502(b). The dates and locations of the public hearings will be announced as soon as practicable.

EFFECTIVE DATE

As stated above, the Commission has determined that a delay of the effective date of the regulations beyond the effective date of the Natural Gas Policy Act is impractical and contrary to the public interest. Accordingly, the Commission finds that good cause exists for making the regulations effective on December 1, 1978.

(Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. 791 *et seq.*, Federal Energy Administration Act, 15 U.S.C. 761 *et seq.*, Natural Gas Policy Act of 1978, P.L. 95-621, 92 Stat. 3350, Department of Energy Organization Act, P.L. 95-91, E.O. 12009, 42 F.R. 46267)

In consideration of the foregoing, Chapter I of Title 18, Code of Federal Regulations, is amended as set forth below.

By the Commission.

Lois D. Cashell

Lois D. Cashell
Acting Secretary

PART 2 - GENERAL POLICY AND INTERPRETATIONS

1. Section 2.68 is amended by adding a new paragraph (c) to read as follows:

§ 2.68 Policy with respect to temporary emergency sales and deliveries of natural gas for resale in interstate commerce by persons with exemptions under the Natural Gas Act pursuant to section 1(c), and certain persons exempt under the Natural Gas Act pursuant to section 1(b).

* * * * *

(c) This section does not apply to any transaction other than an existing emergency transaction (as defined in § 157.46(i)).

PART 157 - APPLICATIONS FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND FOR ORDERS PERMITTING AND APPROVING ABANDONMENT UNDER SECTION 7 OF THE NATURAL GAS ACT

2. Section 157.22 is amended by adding a new paragraph (f) to read as follows:

§ 157.22 Exemption of temporary acts and operation.

* * * * *

(f) This section does not apply to any transaction other than an existing emergency transaction (as defined in § 157.46(i)).

3. Section 157.29 is amended by adding a new paragraph (e) to read as follows:

§ 157.29 Exemption of emergency sales or transportation.

* * * * *

(e) This section does not apply to any transaction which is not an existing emergency transaction (as defined in § 157.46(i)).

4. Part 157 is amended by adding new Subparts C (§§ 157.45 through 157.52) and D (§ 157.53), to read as follows:

[New Subpart C is reflected in the "Regulations" division at ¶ 19,595 to 19,602; new Subpart D is reflected at ¶ 19,603.]

5. Chapter I of Title 18 is amended by adding new Subchapters H and I to read as follows:

[New Subchapter H, Parts 270 to 276, is reflected in the "Regulations" division at ¶ 24,000 to 24,617; new Subchapter I, Part 284, is reflected at ¶ 24,850 to 24,915.]

[¶ 30,027]

43 F. R. 57247 (December 7, 1978)

[Docket No. RM79-7]

PART 154—RATE SCHEDULES AND TARIFFS

Final Regulation Allowing Jurisdictional Pipelines with a PGA Clause in Effect on January 1, 1979, Which Includes a Deferred Account, to Include in Their PGA Tariffs, One Time, Certain Estimated Changes in Purchased Gas Cost Due to Implementing the Natural Gas Policy Act of 1978

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: This final rule allows jurisdictional piplelines to waive for one time that provision of the purchased gas adjustment provision (PGA clause) which limits calculation of the surcharge component of the PGA rates to amounts actually reflected in the deferred account. As a result pipelines with a PGA clause in effect on January 1, 1979 may include in their first PGA rate adjustments effective in 1979. Those costs they estimate they have incurred because of the Natural Gas Policy Act (NGPA) but which have not yet been reflected in their deferred account. The relief granted on this regulation is not available to a pipeline which has a PGA clause which does not contain a deferred account.

EFFECTIVE DATE: December 1, 1978.

FOR FURTHER INFORMATION CONTACT:

Mary Jane Reynolds, Office of the General Counsel, Federal Energy Regulatory Commission 825 North Capitol Street, N.E., Washington, D.C. 275-4283.

BACKGROUND

The Natural Gas Policy Act of 1978 ("NGPA") enacted November 9, 1978, takes effect with respect to certain first sales of natural gas delivered on or after December 1, 1978. The staff of the Federal Energy Regulatory Commission (Commission) has conducted an evaluation of the new Act and has made a preliminary estimate that potentially the first year impact of NGPA on interstate pipelines could be as much as $1.7 billion.

The impact of producer price increases resulting from Opinion No. 770-A [1] was at least equivalent to that expected from the NGPA. In Opinion No. 770-A, as well as Opinion No. 699-H [2] which provided for substantial increases in producer prices, the Commission allowed the pipelines special relief to recover the increased costs.

On November 13, 1978, the Interstate Natural Gas Association of America ("INGAA"), in conjunction with its comments on the proposed regulations implementing the NGPA, Docket No. RM79-3, proposed that the Commission permit a special one-time "tracker" to enable interstate pipelines to recover the increased costs associated with NGPA prices. On November 16, 1978, Texas Gas Transmission Corporation ("Texas Gas") [3] proposed a modification of INGAA's special one-time tracker.

The Commission has determined that some special relief is necessary to avoid an undue and adverse impact upon interstate pipelines because of the NGPA. It has considered several possibilities including the INGAA and Texas Gas proposals and the special relief allowed in Opinions 699-H and 770-A. The Commission has adopted a more limited form of relief than those proposed by INGAA and Texas Gas.

It is granting relief similar to that granted by the Federal Power Commission (FPC) in Opinion No. 770-A, with two modifications. In Opinion No. 770-A the Federal Power Commission permitted the pipeline industry a special PGA adjustment, effective December 1, 1976, that allowed the industry to reflect in their current cost of purchased gas price changes based on gas prices in effect in December 1, as well as a twelve-month surcharge to recover increased costs attributable to the opinion that had actually occurred and were estimated tó occur during the period from July 27, 1976, through November 30, 1976. The first modification changes the length of the special surcharge period from twelve months to six months. The second modification changes the effective date from a single date for all companies with PGA clauses to each pipeline company's first regularly scheduled 1979 semi-annual anniversary date.

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[1] Opinion No. 770-A was issued on November 5, 1976, in Docket No. RM75-14.

[2] 52 FPC 1604 (1974).

[3] Transcontinental Gas Pipe Line Corporation joined in the filing with Texas Gas.

DISCUSSION

A. THE REGULATION ADOPTED

Under existing practices, the PGA rate adjustment is composed of two parts: a current adjustment and a surcharge. The current adjustment reflects the prices the pipelines will pay suppliers as of the proposed effective date of the PGA rate adjustment. The surcharge reflects actual amounts included in the deferred account. By the amendment adopted in this order, each pipeline company with a PGA clause in effect on January 1, 1979, which includes a deferred account, may estimate the impact of the NGPA from December 1, 1978, up to its first regularly scheduled PGA rate adjustment date in 1979. However, for those months for which the pipeline has actual costs reflected in its deferred account, no estimate may be made because NGPA costs will be reflected in the deferred account. This amount may be added to the actual amount in the pipeline's deferred account for purposes of calculating the pipeline's first PGA surcharge rate adjustment to be effective on or after January 1, 1979.

Those companies which have PGA tariff sheets on file with an adjustment date of January 1 may at their option, include the special relief adjustment allowed for NGPA costs either (1) in the PGA rate adjustments to become effective on January 1, 1979 or (2) in their first PGA rate adjustments filed on or after January 1, 1979. Those pipelines which choose to include this special relief in their PGA rate adjustments to be effective on January 1, 1979 shall make an amended PGA rate adjustment filing with a proposed effective date of January 1, 1979. The amended rate filing shall be made as promptly as possible; but no later than December 15, 1978. The notice requirements of § 154.38(d)(4)(v) and the notice provisions of the pipelines' PGA clause tariff provisions are waived for this filing.

The special relief granted herein waive certain provisions in the PGA clause. As a result, it will apply only to those companies which elect[4] to use the PGA option, which include a deferred account, to recover all changes in purchased gas cost for the three year period commencing on January 1, 1979. Companies which have elected the non-PGA option must recover all changes in purchased gas costs, including those due to the impact of NGPA, in general section 4 rate filings pursuant to § 154.63.

The PGA provisions only allow for recovery of actual amounts reflected in the deferred account (Account 191).[5] The effect of this provision is that the PGA surcharge would not include or recover amounts attributable to the NGPA up to 90 days prior to the effective date of the surcharge adjustment. Thus increases in flowing gas supplies attributable to the NGPA and incurred by pipelines within up to 90 days before the filing of a PGA rate adjustment would have to be carried by the pipeline until its succeeding PGA rate adjustment absent some form of relief. However, this understates the problem, because Order No. 13 specifies semi-annual filing dates for PGA tariff adjustments. Thus pipelines with PGA clause adjustments effective by operation of Order No. 13 on or before March 1, 1979 would not be able to reflect in their proposed surcharge adjustments any changes in purchased gas costs attributable to the NGPA until as late as September 1979. Thus they would be carrying these NGPA costs for as long as nine months before the normal operation of the PGA clause would allow any recovery whatsoever of statutorily allowed increased purchased gas costs. This situation could cause hardship to some pipeline companies.

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[4] Order No. 16, issued November 27, 1978, in Docket No. RM79-1, requires each pipeline to elect for three year periods whether to recover changes in purchased gas costs through a PGA clause or through general section 4 rate filings.

[5] See CFR § 154.38(d)(4)(iv)(d).

The Commission believes the special relief granted herein is an effective way to minimize the time that companies would be required to carry amounts attributable to NGPA in their deferred accounts. It also minimizes finance charges which would have been attributable solely to deferring collection of NGPA costs. By limiting the estimates to events occurring before the effective date of the PGA tariff adjustment, this method avoids the difficulties inherent in projecting future occurrences.

In sum, the Commission believes the amendment, in conjunction with the operation of Order No. 13 provides for a more orderly and gradual flowthrough of changes in purchased gas costs due to NGPA than would result if any of the other options discussed (*infra*) in this order were adopted.

B. OTHER OPTIONS WERE CONSIDERED

The proposals presented by INGAA[6] and Texas Gas[7] are very similar. Under INGAA's proposal, interstate pipelines with an effective PGA clause would be permitted a one-time adjustment, effective January 1, 1979, that would recover, through a surcharge, estimated increased purchased gas costs contributable to the NGPA of 1978 from December 1, 1978 to their next regularly scheduled semi-annual PGA anniversary date. Texas Gas proposes to modify the above proposal by giving interstate pipelines the option of delaying their one-time tracker until their first regularly scheduled semi-annual PGA anniversary date subsequent to January 1, 1979. Texas Gas' proposal is based upon a surcharge that would recover increased purchased gas costs attributable to the NGPA of 1978 from December 1, 1978 to their second regularly scheduled semi-annual PGA anniversary date subsequent to January 1, 1979.

Pacific Gas & Electric Company (PG&E) urged that the Commission deny the request by INGAA and suggested that the cost increases resulting from the implementation of NGPA should continue to be accumulated by the interstate pipeline companies and recovered at the time of their regularly scheduled PGA change date.[8] PG&E noted that Order No. 13 authorizes carrying charges on deferred balances in Account 191, which ameliorates the burden upon interstate pipelines.

Both the INGAA and Texas Gas proposals would permit the pipelines to estimate future changes in gas costs for as much as six months subsequent to the adjustment date. The Commission finds the use of such estimates undesirable because of the uncertainty involved in making estimates of future gas prices under the NGPA. For example, the pipelines would be required to estimate not only the volume of new supplies, but also when filings for determinations would be made and when the determination of the proper classification of gas that would be made by state regulatory agencies. The pipelines would also be required to estimate future inflation adjustment factors which are a function of future economic conditions of the national economy.

In Opinion No. 699-H the Federal Power Commission granted interstate pipelines with effective PGA clauses relief through a special one-time adjustment of their current cost of purchased gas on a specified date for the industry.

In Opinion No. 770-A the Federal Power Commission granted interstate pipelines with effective PGA clauses relief through a special one-time adjustment of their current cost of purchased gas, plus a twelve-month surcharge, with interest, that would recover estimated increased purchased gas costs attributable to Opinion No. 770-A that occurred during the period from July 27, 1976, through November 30, 1976. The industry was permitted to effectuate these adjustments on December 1, 1976.

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[6] Natural Gas Pipeline Company and El Paso Natural Gas Company support the INGAA proposal.

[7] The Texas Gas proposal is supported by Transcontinental Gas Pipe Line Corporation.

[8] PG&E's proposal would result in the normal operation of the PGA absent any special relief. The effects of this have been discussed previously.

The special relief in Opinion Nos. 699-H and 770-A as well as the INGAA proposal would cause multiple filings and a virtually immediate increase in all rates of a pipeline to its customers which would flow through the increase to the consumer. The numerous filings would impose a substantial administrative burden of the type which the Commission specifically addressed and alleviated by Order Nos. 13 and 16. Moreover, the importance of immediate passthrough of all NGPA costs by all pipelines has been lessened by the recently adopted Order No. 13 which permits carrying charges. Equally significant in rejecting the historic approach which would allow all pipelines to increase their rates simultaneously is the more abrupt increase in costs to the ultimate consumer and the impact this would have on the economy as a whole.

FINDINGS

(1) For the reasons set forth, the Commission finds that it is appropriate and in the public interest in administering the Natural Gas Act to adopt this amendment;

(2) For good cause as more fully described herein, the Commission finds that notice and comment upon the amendment are impracticable and contrary to the public interest;

(3) In view of the purposes, intent and effect of the amendment, good cause exists for making it effective immediately.

(Natural Gas Act (15 U.S.C. 55), Department of Energy Organization Act (42 U.S.C. 7101, *et seq.*), and E. O. 12009, 42 FR 46267.)

CONCLUSION

In consideration of the foregoing, Part 154, Chapter I of Title 18, code of Federal Regulations, is amended as set forth below, effective immediately.

By the Commission.

LOIS D. CASHELL,
Acting Secretary.

1. Section 154.38 is amended in paragraph (4) of paragraph (d) by a sentence at the end of the indroductory language and by adding a new clause (x) to read as follows:

§ 154.38 Composition of rate schedule.

* * * * *

(d) Statement of rate * * *

(4) * * * The first PGA rate adjustment to become effective on or after January 1, 1979, may reflect the calculation specified in clause (x).

(x) *One-time passthrough of certain estimated NGPA costs.* (*a*) *General Rule.* Notwithstanding the provisions of clause (iv)(*d*) of paragraph (d)(4), any natural gas pipeline company with a PGA clause in effect on January 1, 1979, may estimate its changes in purchased gas cost directly attributable to the Natural Gas Policy Act of 1978 (NGPA) up to and including the month preceding the effective date of its first PGA tariff adjustment effective on or after January 1, 1979, provided however, for those months for which the pipeline has acutal NGPA costs reflected in its deferred account, the actual amounts must be used in calculating the surcharge. The amount estimated may be added to the actual amounts reflected in the pipeline's deferred account (Account 191) for purposes of calculating the PGA surcharge included in the pipeline's first PGA rate adjustment to be effective on or after January 1, 1979.

(*b*) *Option for pipelines with a PGA rate adjustment effective on January 1, 1979.* Those pipelines with PGA rate adjustments to become effective on January 1, 1979 may elect to include the adjustment for NGPA costs prescribed in clause (x)(*a*) either (i) in their PGA rate adjustment to become effective on January 1, 1979, or (ii) in their first PGA rate adjustment filed on or after January 1, 1979. Those pipelines choosing (i) must file amended PGA rate sheets which reflect the adjustment allowed in clause (x)(*a*) no later than December 15, 1978; the notice requirements of § 154.138(d)(4)(v) and the notice provisions in the pipeline's PGA clause tariff provisions are hereby waived for such PGA tariff filings made during December 1978.

[FR Doc. 78-34180 Filed 12-6-78; 8:45 am]

[¶ 30,028]

43 F. R. 57597 (December 8, 1978)

SUBCHAPTER H—REGULATION OF NATURAL GAS SALES UNDER THE NATURAL GAS POLICY ACT OF 1978

[Docket No. RM79-8]

PART 277—OTHER PROVISIONS

Interim Regulation Prescribing 15-Year Minimum Duration for New Contracts for Some Sales of Certain OCS Gas

AGENCY: Federal Energy Regulatory Commission.

ACTION: Interim Rule; request for comments.

SUMMARY: The regulation implements that part of Section 315 of the Natural Gas Policy Act (NGPA) which requires that the Commission prescribe a minimum contract duration for certain outer continental shelf (OCS) gas. The regulation applies to new contracts for the sale of gas which qualifies under the NGPA as new or high cost gas. It imposes a minimum contract duration of 15-years or, if less, the commercially producible life of the well.

DATES: Effective date: December 1, 1978. Comments should be submitted on or before January 31, 1979.

ADDRESS: Send comments to Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

Mary Jane Reynolds, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 275-4283.

BACKGROUND

On November 9, 1978, the Natural Gas Policy Act of 1978 (NGPA) was signed into law. By passage of the NGPA, Congress has significantly modified certain aspects of the previously controlling federal regulatory statute, the Natural Gas Act (NGA). Generally, under the Natural Gas Act, natural gas sold for resale in interstate commerce was dedicated to interstate commerce. Once natural gas was dedicated, sales to an interstate pipeline could not be terminated absent Commission[1] authorization.

Therefore, notwithstanding the duration of the contract for the first sale of natural gas by the producer, the pipeline was assured a continued source of supply until depletion or until the public convenience and necessity no longer required the continued sale of the gas to the pipeline. This supply provision protected the pipeline's investment and furthered the ability of the pipeline to meet the requirements of its direct and indirect customers.

Section 601 of the NGPA specifically exempted, new gas (as defined in section 102(c)), gas from new onshore production wells (as defined in section 103(c)) and high cost gas (as defined in section 107(c)(1)-(4)) from the Natural Gas Act, even if that gas was committed or dedicated to interstate commerce on November 8, 1978. Gas dedicated to interstate commerce and not exempted by the NGPA remains subject to all existing requirements under the Natural Gas Act. If a producer sale of gas is not subject to the Commission's jurisdiction under the NGA, the producer may terminate service without obtaining abandonment authorizations from the Commission under Section 7(b) of the NGA. Assurance of the continuity of supply now lies in the ability of the pipeline to negotiate with the producer contracts of sufficient duration.

With respect to new or high cost gas produced from an Outer Continental Shelf (OCS) reservoir, and exempt from the Natural Gas Act, Congress directed the Commission to prescribe a rule specifying a minimum duration of new contracts for the first sale of natural gas. NGPA section 315(a)(3).[2] According to the statute the minimum duration the Commission may establish for these OCS sales is 15 years, or, if less, the commercially producible life of the reservoir. By the interim regulation adopted today the Commission has prescribed the minimum duration permitted by the statute. A person who suffers special hardship, inequity, or unfair distribution of burden because of the 15-year minimum term may seek an adjustment pursuant to section 502(c) of the NGPA.

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[1] Commission refers to the Federal Power Commission with respect to actions taken before October 1, 1977; and to the Federal Energy Regulatory Commission with respect to actions taken thereafter.

[2] The Commission also has discretion to prescribe the minimum duration of new contracts for the sale of onshore gas. Section 315(a)(1) of the NGPA. At this time the Commission is not exercising this discretionary authority.

SUMMARY OF THE REGULATION

The regulation prescribes the minimum duration for a contract for the first sale of new or high cost natural gas produced from an OCS reservoir. A new contract is one entered into on or after December 1, 1978. The regulation defines new and high cost gas as, *inter alia*, that gas which USGS determines to be new and high priced gas as defined in sections 102(b)[3] and 107(c)(1)-(4) of the NGPA respectively. The procedure for USGS determinations and Commission review thereof is set forth in Parts 274 and 275 of the Interim Regulations issued on November 29, 1978.

The producer of natural gas will not be able to ascertain whether the minimum contract provisions of this part apply to a particular first sale contract until a final determination of the gas as new or high cost is made. However, the Commission recognizes that producers are currently negotiating contracts for first sales of gas for which they intend to apply to USGS for a new or higher price determination. These producers need guidance as to the minimum duration of the contracts during the course of negotiations. Hence the Commission has determined that it is important to reach a determination on this question immediately in order to provide certainty in negotiations. Furthermore, the Commission believes based on information available at this time, that in light of the current natural gas supply situation, the 15-year minimum duration for new OCS contracts will adequately protect the public including the producers, pipelines distribution companies, and ultimate consumers. Similarly, it does not believe that current market conditions require any minimum duration for onshore contracts. Therefore, it is not prescribing a minimum contract duration for new onshore contracts. Should the Commission subsequently determine that a minimum onshore sales of natural gas is necessary, it will issue such a regulation for prospective application.

COMMENT PROCEDURE

The Commission invites comment on all aspects of the regulation promulgated today. In particular, it seeks information on the proper minimum duration of new OCS contracts. The Commission also seeks comments on its tentative decision not to impose a minimum contract duration on new contracts for the sale of onshore gas.

Written comments on this regulation should be sent to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426. The comments may be incorporated into the comments on the Interim Regulations under the Natural Gas Policy Act in Docket No. RM79-3 (issued November 29, 1978). Comments not filed as part of Docket No. RM79-3 should reference Docket No. RM79-8 on the envelope and on the document itself. To assist the Commission, it is requested that comments state whether the matters addressed are, technical, legal, or policy matters, and if alternative approaches are suggested, that comments include proposed implementing language to the extent practicable.

Fifteen copies should be submitted. All comments and related information received by the Commission by January 31, 1979, will be considered prior to promulgation of revisions or amendments to this regulation.

PUBLIC HEARINGS

The Commission intends to hold a series of public hearings on the interim regulations Docket No. RM79-3 as required by section 502(b) of the NGPA. Comments on this regulation may be included in the oral presentations at these hearings. The dates and locations of the public hearings will be announced as soon as practicable.

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[3] Section 315(a)(3) imposes the minimum contract requirement *inter alia* on "* * * new natural gas (as defined in section 102(b) * * *" This appears to be a clerical error since new natural gas is defined in section 102(c) gas and is exempted from the Natural Gas Act under section 601(a)(1)(B) of the NGPA.

Effective Date

As stated above, the Commission has determined that a delay of the effective date of the regulations beyond the effective date of the Natural Gas Policy Act is impractical and contrary to the public interest. The Commission finds that good cause exists for making the regulations effective on December 1, 1978, without prior notice and comment and without publication 30 days prior to the effective date.

(Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350.)

In consideration of the foregoing, Chapter I of Title 18, Code of Federal Regulations, is amended to set forth below.

By the Commission.

Lois D. Cashell,
Acting Secretary.

1. Subchapter H of Chapter I of Title 18 is amended by adding a new Part 277 to read as follows:

PART 277—OTHER PROVISIONS

§ 277.101 Duration of new contracts for first sale of certain OCS gas.

(a) *Applicability.* This section implements section 315(a)(3) of the NGPA and applies to any new contract for the first sale of high cost natural gas or new natural gas produced from any reservoir on the OCS.

(b) *General rule.* Any contract to which this section applies shall be for a duration of not less than 15 years, or, if less, the commercially producible life of the reservoir.

(c) *Definitions.* For purposes of the section:

(1) "High cost natural gas" means natural gas which a jurisdictional agency has determined, in accordance with Parts 274 and 275 to be high cost natural gas (as defined in section 107(c) (1), (2), (3), or (4) of the NGPA);

(2) "New natural gas" means natural gas which a jurisdictional agency has determined in accordance with Parts 274 and 275 to be new natural gas (as defined in section 102(c) of the NGPA); and

(3) "New contract" means any contract executed after December 1, 1978.

[FR Doc. 78-34284 Filed 12-7-78; 8:45 am]

[¶ 30,029]

43 F. R. 57598 (December 8, 1978)

SUBCHAPTER I—OTHER REGULATIONS UNDER THE NATURAL GAS POLICY ACT OF 1978

[Docket No. RM79-9]

PART 286—ADMINISTRATIVE PROCEDURES

Administrative Procedure—Final Regulation Providing for Stays of Interim Rules Issued Under the NGPA

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: 5 U.S.C. 705, (Administrative Procedure Act) allows the Court to grant stays pending judicial review of a challenged agency action. The Natural Gas Policy Act of 1978 (NGPA) specifically prohibits the court from issuing such stays pending review of rules under the NGPA. By this regulation, the Commission has provided a mechanism where by a person, who believes that an interim regulation is unlawful as applied to such person, may seek an administrative stay.

EFFECTIVE DATE: December 1, 1978.

FOR FURTHER INFORMATION:

Mary Jane Reynolds, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 275-4283.

Background

The Natural Gas Policy Act of 1978 (NGPA), enacted November 9, 1978, mandates a new legislative framework for the regulation of the natural gas industry. The statute affects sales, transmission, and distribution of natural gas, and includes many transactions previously exempt from federal regulation.

One major change in the NGPA is the substitution of a series of specific statutory maximum price levels applicable to discrete types of first sales of natural gas. The Federal Energy Regulatory Commission (Commission) was mandated to implement this portion of the statute by promulgating regulations to be effective no later than December 1, 1978. To this end, interim regulations, Docket No. RM 79-3, were issued on November 29, 1978.

Additional interim regulations, Docket No. RM 79-8, were approved by the Commission on December 1, 1978. Section 506(b) of the NGPA makes the provision of the Administrative Procedure Act (5 U.S.C. 705), authorizing judicial stays of agency action, inapplicable to regulations under the NGPA, including the interim regulations. Therefore, in order to provide persons who believe that any particular provision of the interim regulation is unlawful with a procedure for immediate relief, the Commission is providing a mechanism for seeking an administrative stay.

DISCUSSION

A. SUMMARY OF THE REGULATION

A person who believes any particular provision of the interim regulation issued under the NGPA is unlawful, may apply to the Commission for a stay of that provision as it applies to that person.

The content and filing requirements for applications for stays are detailed in the regulation. Applicant must set out with particularity the provision of the rule for which a stay is sought, a statement of the irreparable injury that will inure to the applicant if a stay is not granted, and the facts and legal arguments in support of its position that the regulation is unlawful.

The Commission may grant a stay in whole or in part by issuing an order which specifies the scope of the stay and the effective dates.

Unless a stay is issued, the applicant must remain in compliance with the rule.

FINDINGS AND CONCLUSION

For the foregoing reasons, the Commission has determined that the regulation should be effective immediately. In as much as the regulation is procedural, the requirement for notice, comment and publication 30-days prior to effective date does not apply. This final regulation is effective December 1, 1978, without prior notice and comment and without publication 30-days prior to the effective date.

(Administrative Procedure Act, 5 U.S.C. 551 *et seq.*, Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, Department of Energy Organization Act, Pub. L. 95-91, E. O. 12009, 42 F.R. 46267)

In consideration of the foregoing, Subchapter I of Chapter I of Title 18, Code of Federal Regulations, is amended as set forth below.

By the Commission.

LOIS D. CASHELL,
Acting Secretary.

Subchapter I of Chapter I of Title 18, is amended by adding a new Part 286 to read as follows:

PART 286—ADMINISTRATIVE PROCEDURES

§ 286.101 Application for stay.

(a) *General rule.* Any person who believes that any provision of an interim regulation issued under the Natural Gas Policy Act of 1978 is unlawful as applied to such person may file an application for stay.

(b) *Content of application.* The application shall state, clearly and concisely:

(1) The provision of the regulation, by section, paragraph, subparagraph and clause, as appropriate, which applicant seeks to have stayed;

(2) The conditions which the applicant believes require the stay, including the irreparable injury which the applicant believes will result if the stay is not granted; and

(3) The factual and legal basis for applicant's contention that the interim regulation is unlawful.

(c) *Filing requirements.* The application shall be under oath. An original and three conformed copies shall be filed with the Secretary of the Commission.

(d) *Commission action.* The Commission may grant the application, in whole or in part, by issuing an order specifying the scope of the stay granted and the effective dates of the stay.

[FR Doc. 78-34283 Filed 12-7-78; 8:45 am]

[¶ 30,030]

43 F. R. 60438 (December 28, 1978)

SUBCHAPTER E—REGULATIONS UNDER THE NATURAL GAS ACT

[Docket No. RM78-23]

PART 154—RATE SCHEDULES AND TARIFFS

Interstate Pipeline Recovery of State of Louisiana First Use Tax

AGENCY: Federal Energy Regulatory Commission.

ACTION: Interim Rule, request for comments.

SUMMARY: This interim rule amends the procedures, established in Order No. 10 (43 FR 45553, October 3, 1978), for recovery of the Louisiana First Use Tax by interstate natural gas pipelines. The rule sets forth the rate treatment and accounting procedures to be followed until a final and non-appealable court determination of the constitutionality of the Louisiana First Use Tax is made.

DATES: This interim rule is effective as of December 20, 1978. Written comments must be received prior to January 25, 1979.

ADDRESS: Comments should be submitted to the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, and should reference Docket No. RM78-23.

FOR FURTHER INFORMATION CONTACT:

William Topping, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, Phone: 202-275-5619.

On August 28, 1978, the Commission issued Order No. 10[1] which amended 18 CFR 154.38 of its Regulations promulgated pursuant to the Natural Gas Act, by adding a new paragraph (18 CFR 154.38(h)). Paragraph (h) establishes procedures governing pipeline recovery of the State of Louisiana First Use Tax on Natural Gas.[2] This new paragraph provides that no pipeline shall be permitted to reflect in its rates costs associated with the First Use Tax prior to the date such tax is finally determined to be valid and consitutional unless a pipeline can show (a) it has undertaken all legal action available to it to determine the constitutionality of the tax; and (b) it will be able to recover the amounts paid to Louisiana if the tax is later found to be invalid. If the pipeline can demonstrate the foregoing, Order No. 10 permits the pipeline to collect the tax, subject to refund, pursuant to a temporary tracking mechanism similar to a purchased gas adjustment clause. Under Order No. 10, pipelines are only permitted to reflect the First Use Tax pursuant to this temporary tracking mechanism. They are not permitted to reflect the First Use Tax in general section 4[3] rate cases.

Applications for rehearing were filed on September 20, 1978, by Northern Natural Gas Company and on September 27, 1978, by Associated Gas Distributors, Tennessee Gas Pipeline Company, Consolidated Gas Supply Corporation, Bear Creek Storage Company, Stingray Pipeline Company,

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[1] 43 FR 45553 (October 3, 1978) (As corrected by Errata Notice of September 15, 1978).

[2] 1978 La. Sess. Law Serv. 462 (Act No. 294), to be codified as La. Rev. Stat. §§ 47:1301-47:1307. Hereinafter referred to as "First Use Tax."

[3] 15 U.S.C. 717c.

Trunkline Gas Company and Panhandle Eastern Pipe Line Company, Columbia Gas Transmission Corporation, United Gas Pipe Line Company, Southern Natural Gas Company, Texas Eastern Transmission Corporation, El Paso Natural Gas Company, Interstate Natural Gas Association of America, and Texas Gas Transmission Corporation. On October 2, 1978, the Attorney General of the State of Louisiana filed a letter of comment; on October 3, 1978, the American Gas Association filed an Amicus Brief; and on October 6, 1978, the Interstate Natural Gas Association of America filed a request for oral argument.

On October 20, 1978, the Commission granted the applications for rehearing of Order No. 10 for the purpose of further consideration. The applications for rehearing raise the following issues:

(i) Whether the First Use Tax is entitled to a presumption of constitutionality until judicially determined invalid.

(ii) Whether the First Use Tax is a recoverable cost of providing service.

(iii) Whether in order to recover the First Use Tax from pipeline customers, pipelines should be required to comply only with Louisiana statutes which provide a mechanism for refunding taxes paid under protest if the tax is found invalid (La. Rev. Stat. § 47.1576).

(iv) Whether Order No. 10 incorrectly or inadequately dealt with several costs associated with the First Use Tax including interest, carrying charges, surcharges, and any court ordered bond payment.

(v) Whether prohibiting recovery of the First Use Tax through a general section 4 rate filing is unlawful and outside the authority of the Commission under the Natural Gas Act.

(vi) Whether Order No. 10 and the regulation promulgated therein violate the Administrative Procedure Act (5 U.S.C. 551, *et seq.*) and the right to due process of law.

Before responding to the specific issues raised in the applications for rehearing, some general comments are in order. The Commission recognizes the interest and concern which have been raised by the numerous applications for rehearing of Order No. 10. In response to the issues raised by the numerous applications for rehearing, the Commission is modifying Order No. 10 and amending § 154.38. In addition, we shall provide an opportunity for comment as described below.

The Commission is making this amendment effective upon the date of issuance of this order because good cause exists to proceed without compliance with the notice, public procedure, and effective date provisions of 5 U.S.C. 553. Under Order No. 10, which is presently still in effect, pipelines are prohibited from reflecting the First Use Tax in general section 4 rate cases. The Commission is concerned that a delay in the effective date of this amendment until after public comment would trigger a flood of section 4 rate filings to reflect the First Use Tax during the comment period. Allowing pipelines to reflect the First Use Tax in their general section 4 rate cases would result in needless administrative burdens and costs, and would inadequately protect the public interest.[4] Therefore, the Commission finds that prior notice and public procedure would be impracticable, unnecessary, and contrary to the public interest.[5] Although the amendment is being made effective immediately, interested persons are invited to submit written comments, data, views or arguments with respect to the amendment.[6]

I. PRESUMPTION OF CONSTITUTIONALITY

Several applicants argued that the Commission and the pipelines are bound by the provisions of the First Use Tax until the Courts declare otherwise.[7] Order No. 10 does not violate this principle of law.[8] Order No. 10 does not advocate that pipelines should violate any provisions of the First Use Tax, nor does it make a determination as to its constitutionality. Rather Order No. 10 establishes procedures by which pipelines can recover the costs attributable to the First Use Tax. These procedures do not deny or relieve pipelines from their duty to comply with the First Use Tax until a final determination of validity is made.

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[4] See Section V, *infra*, for a complete discussion of the disallowance of section 4 rate increases.

[5] See Section VI, *infra*, for a complete discussion of "good cause."

[6] See Section IX, *infra*.

[7] Applicants cited the following cases in support of their contention that an act is presumed constitutional until judicially determined invalid. *U.S.* v. *Carolene Products Co.*, 304 U.S. 144 (1938); *Williams* v. *General Foods Corp.* 492 F.2d 399, 408 (7th Cir. 1974); *Davies Warehouse Co.* v. *Bowles*, 321 U.S. 144 (1944); *McDonald* v. *Board of Election*, 394 U.S. 802, 808 (1969); *Wiley* v. *Memphis Police Department*, 548 F.2d 1247, 1251 (6th Cir. 1977); *Carey* v. *Greyhound Bus Co.*, 500 F.2d 1372, 1379 (5th Cir. 1974).

II. RECOVERABLE COST OF PROVIDING SERVICE

Relying on the ratemaking principle that a utility is entitled to recover its reasonably and prudently incurred costs of providing service [9] and relying on several court cases and Federal Power Commission opinions [10] which have held that taxes are properly incurred costs, applicants [11] argued that the First Use Tax is a recoverable cost of providing service.

Whether taxes are always recoverable costs [12] or whether the First Use Tax is a recoverable cost are not issues in this proceeding. Order No. 10 does not deny the pipelines the right to recover the First Use Tax, but rather restricts the manner by which the pipelines can recover the tax from their customers. Instead of allowing recovery through a general section 4 rate increase, recovery is allowed pursuant to a temporary tracking provision similar to a purchased gas adjustment clause. In addition, an escrow account has been established to protect customers' funds until final determination of the constitutionality of the tax is made. These procedures are necessary to insure just and reasonable rates and to protect consumers from being charged with any unnecessary or illegal costs.

It should be noted that there may be one situation in which pipelines might absorb the loss of tax payments made to Louisiana. If the First Use Tax is determined invalid or unconstitutional by a final and non-appealable court order, and should Louisiana decide not to return all funds collected, then the pipelines will have to absorb the loss of those funds not returned. The Commission has a duty to allow only such rates as will prevent consumers from being charged with any unnecessary or illegal costs. *NAACP* v. *FPC*, 425 U.S. 662, 666 (1976). Therefore, if the first Use Tax is found unconstitutional, the pipeline customers should receive refunds plus interest on the total amount that pipelines collected from them, even if the State of Louisiana does not refund all of the revenues it collects. The Commission finds no reasonable basis for concluding and providing that the ratepayers, rather than the stockholders of the pipelines should bear the cost of a tax which is ultimately found to be unconstitutional. El Paso Natural Gas Co., 13 F.P.C. 421,436 (1954); *see also, Tennessee Natural Gas Line, Inc.* v. *FPC,* 221 F.2d 531 (D.C. Cir. 1954); *City of Cleveland, Ohio* v. *FPC,* 525 F. 2d 845, 850 (D.C. Cir. 1976); and *Panhandle Eastern Pipe Line Co.,* 13 F.P.C. 53, 103 (1954).

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[8] The Commission has instituted an action challenging the validity of the First Use Tax in the Middle District of Louisiana. *Federal Energy Regulatory Commission* v. *Shirley McNamara, et al.*, Civil Action No. 78-384 (M.D. La. filed September 29, 1978).

Specifically, the Commission asserted that the First Use Tax is null, void, of no effect, and unenforceable because it contravenes and violates Article I, Section 8, Clause 3 ("Commerce Clause"), Article I, Section 10, Clause I ("Impairment of the Obligation of Contract Clause") and Clause 2 ("Import-Export Clause"), and Article VI, Clause 2 ("Supremacy Clause") of the Constitution of the United States, and Section 20 of the Natural Gas Act (15 U.S.C. 717s), and, as a result, implicates, infringes upon, and conflicts with, the Commission's authority under the Natural Gas Act (15 U.S.C. 717, *et seq.*).

Although the Commission doubts the validity of the First Use Tax statute, it is not attempting to determine the constitutionality of that statute in this docket. We have, instead, provided the procedures prescribed herein to permit recovery of the First Use Tax pending a determination of its validity and to assure prompt refunds if the First Use Tax is found to be unconstitutional.

[9] *FPC* v. *Hope Natural Gas Co.*, 320 U.S. 591 (1944); *West Ohio Gas Co.* v. *Public Utilities Commission (No. 1)*, 294 U.S. 63 (1934); *FPC* v. *Memphis Light Gas and Water Div.* 411 U.S. 458, 466-7 (1973); *FPC* v. *United Gas Pipe Line Co.*, 386 U.S. 237, 243 (1967).

[10] *Mississippi River Fuel Corp.* v. *FPC*, 163 F.2d 433, 437 (D.C. Cir. 1947); *Galveston Electric Co.* v. *Galveston*, 258 U.S 388 (1922); *Midwestern Gas Transmission Company, et al.*, 36 F.P.C. 61, 71-2 (1966); *Wisconsin Michigan Power Company*, 31 F.P.C. 1445, 1500 (1964).

[11] The Associated Gas Distributors application disagreed with this proposition and argued that pipelines should establish, in accordance with their ordinary burden of proof, that the First Use Tax has increased their total cost of service to an extent which denies them a reasonable rate of return.

[12] Although we have generally permitted valid taxes to be a recoverable cost of providing service, we are not bound in determining rates to the use of "any single formula or combination of formulas." See FPC v. *Natural Gas Pipeline Co.*, 315 U.S. 575, 586 (1942). Any costs, including valid taxes, can be denied rate recovery if the total effect of the natural gas rates are never the less "just and reasonable." See FPC v. *Hope Natural Gas Co.* 320 U.S. 591, 603 (1944).

III. PROCEDURAL REQUIREMENTS FOR PIPELINE RECOVERY OF THE FIRST USE TAX

A. COMPLIANCE WITH LA. REV. STAT. § 47:1576 IS INADEQUATE

In Order No. 10, the Commission stated its concern "that there may not be an adequate remedy in Louisiana state law to permit pipelines to recover amounts paid (even under protest) in the event the tax is collected during the period of litigation and is later found to be unconstitutional." This concern prompted the Commission to require a pipeline, in order to collect the tax subject to refund, to demonstrate that "it will be able to recover the tax paid by [it] to the State of Louisiana in the event the tax is declared invalid by a final, nonappealable court order." This concern also prompted the Commission to require all funds collected during the pendency of litigation to be placed in escrow.

Many of the applicants argued that these requirements are not necessary because present Louisiana law permits pipelines to recover all funds paid under the First Use Tax if the taxes are paid under protest. They cite Section 3, Article VII of the Louisiana Constitution of 1934 which provides:

> The legislature shall prohibit issuance of process to restrain the collection of any tax. It shall provide a complete and adequate remedy for the prompt recovery of an illegal tax paid by a taxpayer.

They further argue that La. Rev. Stat. § 47:1576 provides a refund. La. Rev. Stat. § 47:1576 provides that, upon notice of the taxpayer's intention to file suit for the recovery of the amounts paid under protest, the amount remitted shall be placed in an escrow account and held by the collector or his duly authorized representative for a period of thirty days. If suit is filed within the thirty-day period for recovery of the amount, the funds in the escrow account will continue to be held pending the outcome of the suit. If the taxpayer prevails, the collector is required to refund the amount to the claimant, with interest at the rate of six percent (6%) per annum covering the period from the date the funds were received by the collector to the date of refund.

The application of Tennessee Gas Pipeline Company (Tennessee) disputes the contention by many of the other applicants that present Louisiana law guarantees the protesting taxpayer his refund if he wins his claim that the tax is illegal. Tennessee states that, as part of the First Use Tax package, the Louisiana legislature amended Title 47 to add section 1351. Section 1351, which creates the First Use Tax Trust Fund to hold the proceeds from the tax, apparently conflicts with La. Rev. Stat. § 47:1576.

Tennessee believes that the more specific escrow and refund provisions of La. Rev. Stat. § 47:1351(D) may effectively repeal section 1576 insofar as section 1576 would otherwise apply to the escrow and refund of the First Use Tax. If section 1576 is unavailable, pipelines will have to rely upon section 1351(D). Section 1351(D) provides, in pertinent part, that the First Use Tax proceeds will be deposited in a trust fund and will be considered to be in escrow until the State Treasurer, with the concurrence of two-thirds of the State Bond Commission, determines that the funds are available for the uses enumerated in the statute. Thus, the disbursement of the trust fund is within the discretion of the State Treasurer and two-thirds of the Bond Commission. While the remainder of Section 1351(D) indicates that the taxes will be refunded if the tax is finally held invalid, there is no assurance that the funds remaining in the escrow fund will be adequate to refund the total First Use Tax paid. There is no assurance that some portion of the trust fund will not have already been spent. The Commission agrees with Tennessee's conclusion that present Louisiana law may not permit pipelines to recover all protested amounts paid. The Commission therefore finds that compliance with La. Rev. Stat. § 47:1576 is inadequate as a customer safeguard, and that some additional procedures are necessary for protecting pipeline customer's funds. Accordingly, we have provided an escrow account to protect customer funds.

B. AN ESCROW ACCOUNT PROTECTS CUSTOMER FUNDS

The Commission believes that an escrow account is the most efficient method of protecting consumers. The Commission has a duty to protect any payments made by pipeline customers until final determination of the constitutionality of the First Use Tax. Moreover, the United States Court of Appeals for the District of Columbia has found that protection under similar circumstances is appropriate. In *Tennessee Natural Gas Lines, Inc.* v. *Federal Power Commission,*[13] Tennessee Natural Gas contested a Federal Power Commission Order [14] which disallowed a Tennessee Gross Receipts Tax as a proper item of cost of service. At the time of the petition for review of the Commission's order a suit was pending in the Tennessee courts contesting Tennessee Natural Gas's liability for the tax. The Commission's position was that if the courts finally determined that the company was liable for the tax, the inclusion of the amounts as a cost of service would be allowed. The U.S. Court of Appeals for the District of Columbia held:

> "In this posture of the case the ends of justice will best be served by a remand of the matter to the Commission, with directions that *final determination* of the rates be *postponed* until the *termination* of the Tennessee *litigation* and that its order disallowing the item be temporarily suspended. In the meantime the funds resulting from the payment of the higher rates should be *protected*, so that they can be refunded to the company's sole customers in these sales if the ultimate result be to that effect." [emphasis added] [15]

Order No. 10 imposes procedures which implement the aforementioned principles. The Order does not disallow the First Use Tax as a proper item of cost of service, but allows recovery of the tax if certain conditions are met. Order No. 10 creates a separate PGA-type tracking account so that final determination of the rates can be postponed until the issues in litigation are resolved. Since funds paid to the First Use Tax Trust Fund may not be recoverable the Commission has the responsibility of protecting consumers, and has done so through the establishment of an escrow account pursuant to 18 CFR 250.12. Without an escrow account there would be no assurance that the customers would have their funds returned if the First Use Tax is found invalid.

In addition to the escrow requirement of Order No. 10, the amendment herein requires pipelines to comply with La. Rev. Stat. § 47:1576 before they can recover the costs of the First Use Tax from their customers. Although compliance with La. Rev. Stat. § 47:1576 by the pipelines is not necessary to protect the escrowed customer funds, use of the mechanism would prevent an imprudent and automatic loss of funds by the pipeline to the State of Louisiana. Therefore, the amendment adopted in this order retains the escrow requirement of Order No. 10 and modifies Order No. 10 to require pipelines to comply with La. Rev. Stat. § 47:1576.

C. THE AMENDMENT ADOPTED HEREIN DELETES ORDER NO. 10 PREREQUISITE REQUIREMENTS FOR TRACKING THE FIRST USE TAX

Applicants were generally concerned with the prerequisite requirements for tracking the First Use Tax. Order No. 10 permits the collection of the tax subject to refund if the pipeline can show (a) it has undertaken all legal action available to it to determine the constitutionality of the tax, and (b) it will be able to recover the tax paid by it to the State of Louisiana in the event the tax is declared invalid by a

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[13] 221 F.2d 531 (D.C. Cir.1954).

[14] 13 F.P.C. 963 (1954).

[15] 221 F.2d 531, 532 (D.C. Cir. 1954).

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final, nonappealable court order. Both of these requirements have been criticized as conditions which would be difficult to prove. These requirements were established in order to protect the public from possible loss of funds collected. Nevertheless, these requirement are deleted from the amendment adopted herein since the Commission finds that the establishment of an escrow account pursuant to 18 CFR 250.12 and compliance with La. Rev. Stat. § 47:1576 sufficently protect the public from any unjust or unreasonable charge.

D. COURT ENJOINING OF COLLECTION OF THE FIRST USE TAX

In Order No. 10 the Commission stated that if collection of the tax were enjoined by the courts during the period of litigation, no collection of such amounts by pipelines in their jurisdictional rates would be permitted until such time as the tax was found to be lawful by a final and nonappealable court order. We also stated that, in the event collection of the tax was enjoined, the pipelines should keep account of their contingent tax liability during the pendency of court review and appropriate rate relief would be granted by the Commission if the tax was ultimately held to be valid and constitutional. The amendment adopted herein retains these provisions.

One applicant [16] requested that pipelines be allowed to track the cost of any bond which might have to be posted in order for the court to issue an injunction. The Commission postpones determination of this issue until such time as a court takes such action. At that time we could make our decision in light of the actual details of the court opinion.

E. TRACKING PROVISIONS AND TERMINATION OF TRACKING PROVISIONS

Applicants generally requested that the tracking provisions be more explicitly defined. The Interstate Natural Gas Association of America recommended that the Commission allow the filing of applications by pipelines on or before March 1, 1979 for a temporary tracking procedure to become effective April 1, 1979 (the date the tax takes effect). In order to insure that pipelines would comply with the requirements of La. Rev. Stat. § 47:1576, the Interstate Natural Gas Association of America recommended that the applications should be accompanied by an affidavit signed by an authorized representative of the applicant stating that the applicant will comply with the procedures set out in La. Rev. Stat. § 47:1576. In order to insure that pipelines did eventually comply with the statutory protest procedures, the Interstate Natural Gas Association of America recommended that the order approving the application could be conditioned upon the applicant pipeline forwarding to the Commission written evidence that this procedure had been completed.[17] The Commission accepts this recommendation and has incorporated it into the amendment adopted herein.

The Commission also adopts the following provisions for the tracking of the First Use Tax. Should the tax be required to be paid by the pipelines during the pendency of the litigation and should the pipeline comply with the provisions of La. Rev. Stat. § 47:1576, the Commission will waive the filing requirements of § 154.63 of the regulations (18 CFR 154.63) as well as the provisions of § 154.38(d)(3) of the regulations (18 CFR 154.38) in order to permit pipelines to make an adjustment to their rates to be filed on or before March 1, 1979, effective April 1, 1979, subject to refund, to reflect collection of the tax in their rates. The initial amount to be paid by the pipeline from April 1 through the date of its first adjustment date under the temporary tracking provision shall be based upon volumes estimated to be subject to the First Use Tax during that period. The initial rate adjustment shall be calculated on the estimated total system sales for that same period. Coincident with filing the initial rate adjustments, pipelines shall file temporary tracking provisions to provide for semi-annual [18] rate adjustments to coincide with their semi-annual PGAC adjustments.[19] These provisions shall be separate from, but structured like, the respective pipeline's PGA clause, except as otherwise provided in this order. The tracking provisions shall include deferred accounting provisions through use of Account 186, Miscellaneous Deferred Debits, but no carrying charges will be permitted on balances accrued in the deferred account. The deferred account protects the pipeline from permanent under-collections of the tax during the early period the tax is in effect, if the pipelines err in determining which volumes of gas are subject to the tax. The deferred account and the tracking provisions also limit disputes as to amounts to be refunded by pipelines should the tax ultimately be found to be invalid by the courts.

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[16] Southern Natural Gas Company, application at p. 4.

[17] A suit for recover of the First Use Tax cannot be filed until the First Use Tax is paid under protest. La. Rev. Stat. § 47:1576. Liability for the First Use Tax will not begin to accrue until April 1, 1979. The above procedure allows the First Use Tax tracker to be in effect on the date the tax liability begins to accrue and allows the pipelines to collect the tax currently from their customers, thereby avoiding the two months of deferral of the tax that otherwise would result if the Commission required that the pipelines wait until the suit for recovery has been filed before applying for authority to track the tax.

Pipelines which have elected to recover changes in purchased gas costs through general section 4 rate cases under the provisions of Order No. 16 issued November 27, 1978, in Docket No. RM79-1, may also establish a tracking provision patterned after a PGA clause with any two semi-annual adjustment dates which are six months apart.

Should a pipeline not be required to pay the First Use Tax during the pendency of litigation of the constitutionality of the tax, and should the tax be found to be invalid by a final and non-appealable court order, the Commission shall by further order, establish a surcharge, of a reasonable duration, to reimburse pipelines for payments due on the First Use Tax.

Should the tax be paid under protest in accordance with La. Rev. Stat. § 47:1576 and later found to be valid by a final and non-appealable court order, the Commission shall, by further order, terminate the temporary First Use Tax tracking provisions and terminate the escrow account and provide for a final surcharge to clear the balance in the deferred account. At that time, the pipelines would have had an opportunity to become familiar with the tax so that they could determine which volumes of gas were affected by it. Thus, the tax would thereafter be recovered as are most items of cost, i.e., through general section 4 rate filings.

Should the First Use Tax be paid under protest in accordance with La. Rev. Stat. § 47:1576 and later found to be invalid, in whole or in part, by a final and non-appealable court order, the Commission shall, by further order, terminate the temporary Louisiana First Use Tax tracking provisions and terminate the escrow account and provide for an immediate refund with interest to the pipeline customers of the funds collected under the invalid statute and placed in the escrow account. The pipelines would, of course, at that time seek recovery of the taxes paid from the State of Louisiana.

IV. COSTS ASSOCIATED WITH THE FIRST USE TAX: INTEREST AND CARRYING CHARGES

Several applicants requested that ratepayer funds accumulated in the escrow account should be allowed only 6% interest per year while the validity and constitutionality of the First Use Tax is contested. This 6% interest rate is based on the amount of interest refunded by the State of Louisiana under La. Rev. Stat. § 47:1576 if the First Use Tax is found invalid. A six percent interest rate would be inadequate because the pipeline escrow account, and not the State of Louisiana, will be earning interest on the funds collected. Therefore, should a final and non-appealable Court order find the tax to be invalid, in whole or in part, the Commission shall terminate the tracking provisions and escrow account and provide for an immediate refund of those payments made on that portion of the First Use Tax found invalid, plus the corresponding amounts earned by the pipeline on those payments held in escrow.

Many applicants contended that they would have to borrow money in order to pay the tax if their customers' payments of the tax were held in escrow. If the tax is found invalid, by a final and non-appealable court order, the pipelines will receive and retain the interest refunded by the State of Louisiana. The interest refunded by the State of Louisiana will offset costs of borrowing money. If the tax is found valid, by a final and non-appealable court order, the pipelines will be able to receive and retain the funds in the escrow account plus the earnings on those funds. In this manner, the First Use Tax payments by the pipelines to the State of Louisiana and the costs of borrowing those funds will be offset by the funds in the escrow account plus the earnings on those funds.

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[18] Those pipelines with annual PGA rate adjustment provisions could, of course, limit such filings to once a year.

[19] See Order No. 13-A, issued November 27, 1978 in Docket No. R-406.

V. DENIAL OF SECTION 4 RATE INCREASES

Most applicants argued that pipelines have a right to file a section 4 rate increase, recovering prudently incurred First Use Tax payments as a part of their cost of service. They contended that disallowance of such payments is arbitrary and capricious, unlawful and outside the authority of the Commission under the Natural Gas Act. The Associated Gas Distributors (AGD) objected to the prohibition against recovery of the First Use Tax in general section 4 rate cases on different grounds. AGD argued that the special tracking procedures established by Order No. 10 failed to adequately protect the gas consumer against excessive charges because the special tracking procedures exempted pipelines from their ordinary burden of showing that the First Use Tax has increased their total cost of service to an extent which denies them a reasonable rate of return.

The Commission finds that the procedures adopted in Order No. 10, as amended by this order, effectively balance the pipelines' need to recover the First Use Tax and the gas consumers' need to be protected against excessive charges. With regard to the pipelines' arguments, it must be reiterated that Order No. 10 does not disallow recovery of the First Use Tax, but only establishes the procedures by which the tax can be recovered. In creating a distinct mechanism for recovery (PGA-type tracking mechanism) and not allowing recovery through a section 4 rate increase, the Commission was within its authority under the Natural Gas Act, and has provided an alternate recovery mechanism thereby satisfying any "due process" requirements. The Commission may under sections 5 and 16 of the Natural Gas Act restrict filings under section 4(d).[30] Section 5 authorizes the Commission to determine the just and reasonable rate "to be thereafter observed and in force." Section 16 gives the Commission power to make such orders "as it may find necessary or appropriate to carry out the provisions of this act." Denying section 4 recovery of the First Use Tax was and is necessary and appropriate.

The main purpose of establishing the special tracking procedures set forth in this order is to protect consumer from excessive and inappropriate charges. Second, the order prevents the filing of several general section 4 rate cases to recover these charges. The mechanism adopted in this order both protects the consumer and provides an administratively convenient method of handling this complex issue.

The Commission has reasonably exercised its powers under the Natural Gas Act because the procedures established by Order No. 10, as modified by this order, simplify the administative procedures, insure pipeline of adequate recovery of the First Use Tax, and insure expeditious refund of all funds paid by pipeline customers if the First Use Tax is found invalid.

VI. COMPLIANCE WITH THE ADMINISTRATIVE PROCEDURE ACT

Several applicants contend that the Commission failed to comply with the mandatory rulemaking procedures of the Administrative Procedure Act[31] which requires that the agency provide notice of a proposed rulemaking,[32] and an opportunity for public participation or comment.[33] Although the Commission waived the procedural rulemaking steps upon a finding of good cause,[34] applicants contend that good cause did not exist and, if it did exist, the Commission failed to substantiate good cause.

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[30] See *Permian Basin Area Rate Cases*, 390 U.S. 747, 777 (1968); *United Gas* v. *Callery Properties*, 382 U.S. 223, 232 (1965).

[31] 5 U.S.C. 551, *et seq.*

[32] 5 U.S.C. 553(b).

[33] 5 U.S.C. 553(d).

The Administrative Procedure Act recognizes two exceptions to the requirement of notice and public participation: One is for general statements of policy; the other is for a finding of good cause that the procedure is impracticable, unnecessary, or contrary to the public interest. The Commission invoked the latter exception.

Order No. 10 explained that it was in the public interest for Commission to issue Order No. 10 without notice and comment.

First, Order No. 10 determined that special procedures for recovery of the First Use Tax are appropriate:

> Therefore the Commission has determined that certain procedures should be established for recovery of this tax by interstate natural gas pipelines. It is particularly appropriate to established such procedures in light of the fact that this Commission on August 16, 1978, directed the Commission's Solicitor to challenge the constitutionality of the tax in Federal District Court and to seek to enjoin collection of the tax by Louisiana pending completion of judicial review.[35]

The Commission believed it was in the public interest to establish special procedures for pipeline recovery of a tax which was of questionable constitutional validity. It was also imperative to put pipelines on notice that the Commission would allow recovery of the First Use Tax only under those procedures.

Second, Order No. 10 explained the need to establish special procedures to protect pipeline customers and ultimately the public at large:

> The Commission is concerned that there may not be an adequate remedy in Louisiana state law to permit pipelines to recover amounts paid (even under protest) in the event the tax is collected during the period of litigation and is later found to be unconstitutional.[36]

The Commission had to develop procedures to protect the public from loss of funds if the tax was found invalid and no adequate remedy existed in Louisiana state law. The Commission could not permit consumers to go unprotected. As we explained in Order No. 10:

> It is important that this order be issued without notice and public comment procedures to put pipelines on notice that they will not be permitted to reflect the Louisiana First Use Tax in general Section 4 rate cases (which usually involve a 30 day notice period plus a five month suspension by the Commission) in order to collect the Louisiana First Use Tax. If pipelines were planning to file general rate cases to collect the tax, they would have to commence preparation of such cases immediately in order to make the rates effective by April 1, 1979, which is the proposed effective date of the tax.[37]

In order to collect the tax pipelines would have been immediately filing section 4 rate increases. The Commission was concerned that a delay in the effective date of Order No. 10 until after public comment would trigger a flood of section 4 rate filings during the comment period. The Commission feared that such a result would defeat the Commission's purpose of protecting consumers from the economic burden of rate collections in excess of the just and reasonable rate, and therefore proscribed the use of section 4 procedures.

For the aforementioned reasons, good cause also exists to issue the amendment in this order without prior notice and to waive publication of the rule, and to make the rule effective immediately.

VII. SUMMARY

For the reasons stated above, the applications for rehearing are denied except as provided in this order. Since the Commission is allowing a public comment period on the amendment in this order and since this order responds to the issues raised in the applications for rehearing, the Commission denies the request by the Interstate Natural Gas Association of America for oral argument.

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[34] 5 U.S.C. 553(b) (B) provides: [W]hen the agency for good cause finds (and incorporates the finding and a brief statement of reasons therefore in the rules issued) that notice and public procedure thereon are impracticable, unnecessary or contrary to the public interest.

[35] Order No. 10, mimeo at 1.

[36] Order No. 10, mimeo at 2.

[37] Order No. 10, mimeo at 2.

VIII. FINDINGS

(A) The Commission's prior order, Order No. 10, should be clarified and modified consistent with this order.

(B) For the reasons discussed in Order No. 10 and reiterated in the body of this order good cause exists to issue this rule without prior notice to become effective immediately.

(C) Good cause exists, and it is appropriate and in the public interest in the administration of the Natural Gas Act, to waive §§ 154.63 and 154.38(d)(3) of the Regulations to permit special rate filings to reflect the Lousiana First Use Tax, as set forth more fully in the body of this order.

(D) Oral argument would not be of benefit to the Commission in its determination of this rule.

(Natural Gas Act (15 U.S.C. 717 c, f, o); Administrative Procedure Act (5 U.S.C. 553); Department of Energy Organization Act (42 U.S.C. 7101, *et seq.*); and E.O. 12009, 42 FR 46267)

IX. COMMENT PROCEDURES

Although the amendment is made effective immediately, interested persons are invited to submit written comments, data, views or arguments with respect to it. An original and 14 copies should be filed with the Secretary of the Commission. The Commission shall consider all comments received prior to January 25, 1979, and shall determine whether any further modification to the rule adopted in this order should be made. Such modification would become effective from the date of issuance of any order further amending the rule adopted in this order. All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, 825 North Capitol Street NE., Washington, D.C. 20426, during regular business hours. Comments should be submitted to the Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, and should reference Docket No. RM78-23.

In consideration of the foregoing, the Commission hereby orders that:

(A) Except as provided in this order, the applications for rehearing filed by all parties in this proceeding are denied;

(B) The request for oral argument by the Interstate Natural Gas Association of America is denied;

(C) The Commission's Order No. 10 is clarified and modified consistent with this order; and

(D) Part 154, Chapter I of Title 18, Code of Federal Regulations, is amended as set forth below, to become effective immediately.

By the Commission.

KENNETH F. PLUMB,
Secretary.

1. Section 154.38 is amended by revising paragraph (h) to read as follows:

§ 154.38 Composition of rate schedule.

* * * * *

(h) *Pipeline recovery of the State of Louisiana First Use Tax.* (1) Except as provided in subparagraphs (2) and (3) of this paragraph, no pipeline shall be permitted to reflect the costs attributable to the Louisiana First Use Tax in general section 4 rate applications prior to the date the tax is determined to be valid and constitutional by a final and nonappealable court order.

(2) Should a pipeline be required to pay the Louisiana First Use Tax during the pendency of litigation of the constitutionality of the tax, the pipeline will be permitted to collect the tax subject to refund if on or before March 1, 1979, it submits an application for tracking which is accompanied by an affidavit signed by an authorized representative stating that the applicant will undertake the procedures set out in La. Rev. Stat. § 47.1576. Upon completion of this requirement the Commission shall waive the filing requirements of § 154.63 and the provision of § 154.38(d)(3) of its regulations in order to permit the pipeline to reflect the tax in its rate by adjusting its rates, to become effective April 1, 1979, subject to refund, to reflect the estimated effect of the Louisiana First Use Tax. The initial amount to be paid by the pipeline from April 1 through the date of its first adjustment date under the temporary tracking provision shall be based upon volumes estimated to be subject to the Louisiana First Use Tax during that period. The initial rate adjustment shall be calculated on the estimated total system sales for that

same period. In order to continue to collect the tax subject to refund, pipelines must, on or before May 30, 1979, submit such evidence as the Commission shall require in order to determine whether the procedures set out in La. Rev. Stat. § 47.1576 have been complied with. Coincident with filing the initial rate adjustment, pipelines shall file temporary tracking provisions to provide for semi-annual rate adjustments to coincide with their semi-annual PGAC adjustments. The tracking provisions shall include deferred accounting provisions through use of Account 186, Miscellaneous Deferred Debits, but no carrying charges will be permitted on balances accrued in the deferred account. Pipelines which have elected to recover changes in purchased gas costs through general section 4 rate cases pursuant to § 154.38(d)(4)(ix) may establish a tracking provision, which generally follows the PGA regulation, with any two semi-annual adjustment dates which are six months apart.

(3) All funds collected under this paragraph will be held in escrow pursuant to § 250.12, and subject to refund during the pendency of litigation.

(4) Should a final and non-appealable court order find the tax to be valid, the Commission shall by order terminate the temporary Louisiana First Use Tax tracking provisions, terminate the escrow account, and provide for a final surcharge to clear the balance in the deferred account. The tax would thereafter be recovered through general section 4 rate filings.

(5) Should a final and non-appealable court order find the tax to be invalid, in whole or in part, the Commission shall terminate the tracking provisions and escrow account and provide for an immediate refund of those payments made on that portion of the tax found to be invalid plus the corresponding proceeds, including interest earned by the pipeline on the payments held in escrow.

[FR Doc. 78-36116 Filed 12-27-78; 8:45 am]

Regulations Preambles

44 Federal Register (1979)

[¶ 30,031]

44 F. R. 1100 (January 4, 1979)

[Docket No. RM79-4]

PART 154—RATE SCHEDULES AND TARIFFS

Amendments to the Commission's Regulations Relating to Independent Producer Filing Requirements

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Commission is amending its regulations relating to blanket affidavit filing requirements for collection of a maximum lawful price under sections 104 and 106(a) of the Natural Gas Policy Act of 1978. The amendments alter the date upon which a rate change filing takes effect, modify the subscription requirements for the blanket affidavit filing, and provide for protests to blanket affidavit filings.

EFFECTIVE DATE: December 28, 1978.

COMMENTS: Written comments by January 31, 1979.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (Reference Docket No. RM79-4).

FOR FURTHER INFORMATION CONTACT:

Romulo L. Diaz, Jr., Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 275-3771.

Howard Kilchrist, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 275-4539.

A. BACKGROUND

On November 17, 1978, the Federal Energy Regulatory Commission (Commission) issued Final Regulations 43 FR 55756, November 29, 1978) amending Parts 154 and 157 of its regulations relating to producer filing requirements. Although the regulations were made effective upon issuance, the Commission solicited written comments by interested parties. The Commission has received four written comments. In response to these comments and the filings it has received pursuant to the amended regulations, the Commission has decided to modify some of the regulations issued on November 17 and to clarify the meaning and effect of others.

SUMMARY OF AMENDMENTS TO THE COMMISSION'S FINAL REGULATIONS

Under the regulations as amended November 17, 1978, a producer must file a blanket affidavit with the Commission in order to charge and collect a maximum lawful price and any periodic escalations under sections 104 and 106(a) of the Natural Gas Policy Act of 1978 (NGPA). In response to comments in this regard, the Commission emphasizes that these filing requirements are mandatory but that small producers covered by a blanket certificate under § 157.40(b) of the regulations are exempt from their coverage.

The Commission has received many affidavit filings under the amended regulations which do not comply with the subscription requirements in § 154.94(h)(6). That section requires that the affidavit be subscribed in accordance with § 1.16 of the regulations, except that § 1.16(a)(1)(iv), permitting subscription by an authorized attorney, does not apply. The Commission wishes to adopt requirements relative to signing of affidavits which parallel other signature requirements in its regulations implementing the NGPA. Consequently, § 154.94(h)(6) is being amended to require that the affidavit filing be signed in accordance with signature requirements imposed in § 274.201(c) of the interim regulations, which pertains to filing for determinations to be made by jurisdictional agencies. Many of the filings submitted under § 154.94(h) were signed by a responsible official of the filing party and thus comply with the amended rather than the original requirements. The Commission advises that it will deem acceptable, all affidavits filed in accordance with § 154.94(h)(6) as originally promulgated or as amended. Affidavits subscribed by attorneys comply with neither regulation and are not acceptable.

The Commission believes that this amendment to the signature requirements will eliminate the basis for complaint that the responsibility of diligent inquiry imposed upon the affidavit in the last paragraph of the form affidavit (Appendix A to § 154.94) was overburdensome. In most cases, the affidavit will now be signed by a responsible official of a company, for whom such inquiry should be neither unnecessary nor overburdensome.

The Commission declines to adopt one suggestion that the filing party indicate the amount of taxes and any other adjustments to which each sale listed in the blanket affidavit is subject. The Commission contemplates obtaining such information in the future in some other form such as an annual report. The Commission does not now wish to incorporate that information into a filing the single purpose for which is to fulfill the requirements imposed by the Natural Gas Act (NGA) in order to permit collection under the NGPA of the maximum lawful price and periodic escalations.

The Commission is amending § 154.94(h)(2)(iii) to comply with the thirty days' notice requirement imposed by section 4(d) of the NGA. Thus, absent specification in the filing of a later effective date, a rate change filing to collect a base rate takes effect on the thirty-first rather than the thirtieth day after the date of filing, provided the filing has not been suspended or rejected. Paragraph (1) of the Blanket affidavit, Appendix A to § 154.94, is being amended to reflect the fact that, where the two are not synonymous, the filing party rather than the affiant, is the one entitled to collect the maximum lawful price.

We have provided for a new subparagraph 154.94(h)(7) which states explicitly that the filing of a blanket affidavit does not permit the collection of a maximum lawful price which is not contractually authorized.[1] This is consistent with Section 101(b)(9) of the NGPA, which provides that a maximum lawful price shall not "supersede or nullify the effectiveness of the price established under such contract," and with § 270.101(b) of the Commission's Regulations.

The Commission has added a new subparagraph (h)(8) to § 154.94 which sets forth a protest procedure for the affidavit filings required to be made under § 154.94(h)(1). Under this procedure protests are required to be filed within thirty days of the filing of the affidavit, or, in the case of an affidavit filed before December 30, 1978, on or before January 30, 1979.

The Commission is making these amendments effective upon the date of issuance upon a finding that good cause exists to proceed without compliance with the notice, public procedure, and effective date provisions of 5 U.S.C. 553. Changes in rate filing requirements and institution of a protest procedure must be immediately effective in order to avoid an unduly disruptive transition from the pricing rules established under the NGA to those prescribed under the NGPA. For this reason, the Commission has found it necessary to make these amendments effective upon issuance of this order.

WRITTEN COMMENT PROCEDURES

Although these amendments are being made effective immediately, interested persons are invited to submit written comments, data, views or arguments with respect to the amendments. An original and 14 copies should be filed with the Secretary of the Commission. All comments received prior to January 31, 1979, will be considered by the Commission, and if appropriate, further revisions will be made. All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours. Comments should be submitted to the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should reference Docket No. RM79-4. Also since these amendments are directly related to the Interim Regulations promulgated pursuant to the NGPA (43 FR 5648), oral presentations of data, views and arguments on these amendments may be made at the public hearings to be held on the Interim Regulations.

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[1] The question of what contractual authorization is required to permit the collection of the maximum lawful prices under section 104 of the NGPA is not addressed herein. The issue of contractual authorization (either existing contractual provisions or amendments to existing contracts) will be addressed by a subsequent Commission order.

(Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.*, Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267.)

In consideration of the foregoing, Part 154 of Subchapter E, Chapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective immediately.

By the Commission.

KENNETH F. PLUMB,
Secretary.

§ 154.94 [Amended].

1. Section 154.94(h)(2)(iii) is amended in the second sentence by striking out "thirtieth" and inserting in lieu thereof the word "thirty-first."

2. Section 154.94(h)(6) is amended by striking out the first sentence and inserting in lieu thereof the sentence, "Any affidavit filed under subparagraph (1) shall be signed in accordance with § 274.201(c) of this chapter."

3. Section 154.94(h) is amended in paragraph (1) of the Blanket Affidavit Filing Under § 154.94(h) at Appendix A, by striking out "he" and inserting in lieu thereof the phrase "the filing party" and by adding new subparagraphs (7) and (8) to read as follows:

* * * * *

(7) *Contractual authorization.* Except in the case of minimum rate gas (as defined in § 271.402(b)(9) of this chapter), neither the filing of a blanket affidavit, nor the acceptance for filing of such an affidavit by the Commission, will affect any person's contractual right to purchase natural gas at a rate which is less than the applicable maximum lawful price under the NGPA.

(8) *Protest procedure.* Any protest to an affidavit required to be filed under this paragraph shall be filed within thirty days of the filing of the affidavit, or, in the case of an affidavit filed before December 30, 1978, on or before January 30, 1979.

[FR Doc. 79-315 Filed 1-3-79; 8:45 am]

[¶ 30,032]

44 F. R. 2381 (January 11, 1979)

SUBCHAPTER I—OTHER REGULATIONS UNDER THE NATURAL GAS POLICY ACT OF 1978

[Docket No. RM79-12]

PART 286—ADMINISTRATIVE PROCEDURES

Administrative Procedure—Final Regulation Providing for Rehearing of Orders and Rules Issued Under the NGPA

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: This regulation provides for rehearing, at the Commission, of rules and orders issued under the Natural Gas Policy Act. Those persons aggrieved by an agency action subject to rehearing under this rule will be required to seek administrative review prior to judicial review.

EFFECTIVE DATE: January 3, 1979.

FOR FURTHER INFORMATION CONTACT:

Mary Jane Reynolds, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 202-275-4282.

SUPPLEMENTARY INFORMATION: The Natural Gas Policy Act of 1978, Pub. L. 95-612, enacted November 9, 1978, provides a new legislative framework for the regulation of the natural gas industry.

On November 29, 1978, the Commission adopted interim regulations in Docket No. RM79-3, subject to further comment and consideration, to implement those aspects of the new statute requiring immediate treatment—particularly the pricing provisions in Title I which, under section 101(b)(4) of NGPA, became effective on December 1, 1978. 43 FR 56448 (December 1, 1978). As stated in the preamble to these regulations:

> The Commission is directed to administer essentially all of the NGPA and is authorized to perform any and all acts and to prescribe and issue such rules and orders as it finds necessary or appropriate to carry out its functions under the NGPA.
>
> (43 FR 56451) See NGPA, section 501.

The purpose of this regulation is to establish a procedure for rehearing of Commission actions subject to the rehearing requirements in section 506 of NGPA. For the reasons set forth below, we have concluded that those requirements apply to rules and orders subject to review under sections 506 (a) and (b).

Section 506(a) establishes detailed procedures for judicial review in the courts of appeals of any order as defined in 5 U.S.C. 551(6), subject to certain exceptions. Among other things, it specifies time limits, makes the seeking of rehearing a jurisdictional prerequisite to review, and specifies procedures for review of the record by the court. Subsection (b) of section 506 is far less informative. It provides:

> Except as provided in subsections (a) and (c), judicial review of any rule or order, within the meaning of section 551(4) of title 5, United States Code, issued under this Act may be obtained in the United States Court of Appeals for any appropriate circuit pursuant to the provisions of chapter 7 of title 5, United States Code, except that the second sentence of section 705 thereof shall not apply.

Under this language, there is a question whether the procedures and rehearing requirements in section 506(a) also apply to the review of rules under section 506(b).

Section 506(a) of NGPA is similar to the judicial review provisions in section 19(b) of the Natural Gas Act, 15 U.S.C. 717r(b). It has been held that rules promulgated by the Commission under the Natural Gas Act, at least where a record has been developed, are reviewable on petition to the courts of appeals under section 19(b). *City of Chicago, Illinois* v. *FPC*, 458 F. 2d 731 (D.C. Cir. 1971), certiorari denied, 405 U.S. 1074 (1972). All of the procedures applicable to judicial review of orders in section 19(b) of the Natural Gas Act have thus been applied to judicial review of record-based regulations under the Natural Gas Act, including the specified time limits for seeking judicial review requirements for rehearing before the Commission, and provisions for stay. *City of Chicago* did not directly address the reviewability of Commission regulations where no evidentiary record had been compiled, because the rules in that case were based upon an evidentiary record. 458 F. 2d at 740-741.

Thus, under the NGA, it is at least arguable that rules not based upon such a record are outside the scope of section 19(b) and therefore may be reviewed only in the district courts. *Id.* at 740. *Cf. United Gas Pipe Line Co.*, v. *FPC*, 181 F. 2d 796, certiorari denied, 340 U.S. 827. Whatever merit this argument might have for purposes of the NGA, subsection (b) of section 506 of NGPA clearly forecloses it for purposes of the NGPA. Congress specified in section 506(b) that judicial review of regulations shall be available in the courts of appeals in accordance with the provisions for judicial review specified in the Administrative Procedure Act, 5 U.S.C. 701-706. But these provisions do not prescribe detailed procedures. Section 703 of that act states only that "the form of proceeding for judicial review is the special statutory review proceeding relevant to the subject matter in a court specified by statute or, in the absence or inadequacy thereof, any applicable form of legal action, including actions for declaratory judgments or writs of prohibitory or mandatory injunction or habeas corpus, in a court of competent jurisdiction. Except to the extent that prior, adequate, and exclusive opportunities for judicial review are provided by law, agency action is subject to judicial review in civil or criminal proceedings for judicial enforcement." Whether rehearing is required or not under Section 506(b) is thus not expressly answered by the APA. We, therefore, turn back to the language and structure of section 506 to determine whether it provides "the special statutory review proceeding" or a guide to "the applicable form of legal action."

Subsection (a) of section 506 provides for review of "orders," *i.e.*, final agency dispositions other than rulemaking but including licensing (5 U.S.C. 551(6)), but excludes orders for civil enforcement under section 504(b) [1] and orders under the emergency authority provisions in sections 302 and 303 of NGPA. Subsection (c) of section 506 provides for judicial review of actions under the emergency authority in the Temporary Emergency Court of Appeals in accordance with the procedure set forth therein. Civil penalty orders are subject to review *de novo* in enforcement proceedings initiated by the Commission in the district courts under section 504(b)(6)(F). Subsection (b) of section 506, relating to rules, however, states that review lies in courts of appeals "except as provided in subsections (a) and (c)." The joint explanatory statement of the Committee on Conference contained in the Conference Report on the NGPA (H.R. Rep. No. 95-72, October 10, 1978) states at page 122 that "[t]he conference agreement provides judicial review based upon the Natural Gas Act * * *." It would appear, therefore, that the limiting phrase "except as provided in subsections (a) and (c)," refers only to the categories of orders excluded from subsection (a) (*i.e.*, orders assessing civil penalties, or any order under sections 302 or 303, relating to emergency authority); and to the matters within the exclusive jurisdiction of TECA under subsection (c), *i.e.* "civil cases and controversies under section 301, 302 or 303, including any order issued, or other action taken, under such section." For the foregoing reasons, the Commission has determined to give effect to the expressed intention of the Statement of Managers that generally the judicial review procedures under the NGPA should follow those under the Natural Gas Act. Thus, insofar as rehearing is concerned the review procedures for rules under section 502(b) will be the same as for rules issued under the Natural Gas Act and follow those expressly provided for under section 502(a). However, the Commission recognizes that there is a key difference in the judicial authority to grant stays pending judicial review of rules issued under the NGPA and the Natural Gas Act.

Section 506(a) expressly requires that any party aggrieved by an order must seek rehearing within 30 days after the issuance of the order, and that the Commission must act on the application within 30 days, or it will otherwise be deemed denied by operation of law. Under this provision "[n]o person may bring an action under this section to obtain judicial review of any order of the Commission unless" he has exhausted the rehearing remedy. Rehearing is thus a jurisdictional prerequisite. Accordingly, by this order, the Commission is adopting a procedure whereby any person aggrieved by any rule or order of the Commission subject to review under sections 506(a) or (b) may request rehearing by the Commission.

A person aggrieved by an order or rule issued under the NGPA and subject to judicial review under section 506(a) and (b) may file an application for rehearing within 30 days after the order or rule being challenged is issued by the Commission. However, the Commission recognizes that part or all of the 30-day period for requesting rehearing has expired with respect to certain rules and orders issued under the NGPA. Accordingly, the Commission is providing 30 days from issuance of this rule implementing rehearing procedures, that is until February 2, 1979, to request rehearing of rules and orders issued on or before January 3, 1979. A person will not be considered to have exhausted administrative remedies until an application for rehearing has been filed, and it has been disposed of under this section. After a person's administrative remedies have been exhausted, that person may seek judicial review as prescribed in section 506 of the NGPA.

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[1] The exclusion refers to "an order assessing a civil penalty under Section 504(b)(4)." That clause provides for injunctive relief to be issued by a court in any action by the Commission to enforce NGPA, or rules and orders thereunder. Commission orders assessing civil penalties are authorized by Section 504(b)(6). The words of the statute indicate that the reference to subsection (b)(4) was a technical error, and that Congress intended to exclude civil penalty orders under section 504(b)(6).

The content and filing requirements for applications for rehearing are detailed in the regulation. Applicant must set out with particularity the provision of the order or section or sections of the rule for which rehearing is sought, the grounds for rehearing and the facts and legal arguments in support of its position.

The Commission may grant rehearing in whole or in part by issuing an order which specifies the scope of the rehearing. Unless the Commission acts upon the application within 30 days after it is filed, the application will be deemed to be denied. If the Commission grants rehearing in part, any part of the application outside the scope of the order granting rehearing shall be considered to have been denied.

FINDINGS AND CONCLUSION

For the foregoing reasons, the Commission has determined that the regulation should be effective immediately. Inasmuch as the regulation is procedural, the requirement for notice and comment do not apply. This final regulation is effective, without prior notice and comment and without publication 30 days prior to the effective date.

(Administrative Procedure Act, 5 U.S.C. 551 *et seq.*, Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, Department of Energy Organization Act, Pub. L. 95-91, E. O. 12009, 42 F. R. 46267.)

In consideration of the foregoing, Chapter I of Title 18, Code of Federal Regulations, is amended as set forth below.

By the Commission.

KENNETH F. PLUMB,
Secretary.

Subchapter I of Chapter I of Title 18, is amended at the end of Part 286 by adding a new § 286.102 to read as follows:

§ 286.102 Application for rehearing.

(a) *General rule.* Any person aggrieved by any order or regulation or any amendment to a regulation issued under the NGPA and subject to judicial review under section 506(a) or (b) thereof shall file a petition for rehearing within 30 days after the order or regulation is issued by the Commission or February 3, 1979, whichever is later. There has not been an exhaustion of administrative remedies until a petition for rehearing has been filed under this section and the proceeding is complete by the denial of the request, or if rehearing is granted, an order affirming, modifying or revoking the challenged order or regulation is issued.

(b) *Specifications of error.* The application for rehearing shall state clearly and concisely with respect to the challenged order or regulation:

(1) The provision of the order or the regulation, by section, and where appropriate, by paragraph;

(2) Applicant's interest in the particular provision; and

(3) The facts and legal analysis upon which the request for rehearing is based.

(c) *Procedural requirements.* Except as otherwise provided in this section, the procedures for rehearing in Part 1, Subchapter A, Chapter I shall apply.

(d) *Commission action upon the application.*

(1) The Commission may grant the request for rehearing, in whole or in part, by issuing an order specifying the scope of rehearing. If, and to the extent that rehearing is granted, the Commission may request Staff, applicant or any other party to file briefs. In every case where rehearing is granted, the Commission will issue an order affirming, modifying or revoking the challenged order or regulation.

(2) The Commission may modify the original order or regulation without further hearing.

(3) Unless the Commission acts upon the application within 30 days after it is filed, such application shall be considered to have been denied. If the Commission grants rehearing in part, any part of the application outside the scope of the order granting rehearing shall be considered to have been denied.

[FR Doc. 79-979 Filed 1-10-79; 8:45 am]

[¶ 30,033]

44 F. R. 5874 (January 30, 1979).

[Docket Nos. RM79-3, RM79-4]

PUBLICATION OF PRESCRIBED MAXIMUM LAWFUL PRICES UNDER THE NATURAL GAS POLICY ACT OF 1978 AND AMENDMENTS TO REGULATIONS RELATING TO MINIMUM RATE GAS

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final Rule.

SUMMARY: Notice is hereby given that the Federal Energy Regulatory Commission is publishing maximum lawful prices and inflation adjustment factors for February, March and April 1979 and is amending its regulations regarding pricing and filing requirements for minimum rate gas. The price of such gas is to be stated in terms of Mcf's rather than MMBtu's. Collection of such price is subject to the blanket affidavit filing requirements for producers.

DATES: *Effective Date:* January 25, 1979.

Comments: Written comments by March 1, 1979.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

Romulo L. Diaz, Jr., Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol St., NE., Washington, D.C. 20426 (202) 275-3771.

Howard Kilchrist, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol St., NE., Washington, D.C. 20426 (202) 275-4539.

AMENDMENTS TO REGULATIONS

Issued January 25, 1979.

Publication of Prescribed Maximum Lawful Prices Under the Natural Gas Policy Act of 1978 and Amendments to Regulations Relating to Minimum Rate Gas, Docket No. RM79-3, Docket No. RM79-4.

A. BACKGROUND

On December 1, 1978, the Federal Energy Regulatory Commission (Commission) issued Interim Regulations (43 FR 56448, December 1, 1978), implementing the Natural Gas Policy Act of 1978 (NGPA), Pub. L. No. 95-621, 92 Stat. 3350. Sections 271.101(a), 271.202, 271.302, 271.402(a), 271.602, 271.702, 271.802, 271.902 and 273.201(a)(1) of the interim regulations set forth the maximum lawful prices per MMBtu for deliveries made in December 1978 and January 1979. Section 271.102(c) sets forth the monthly inflation adjustment factors. Section 101(b)(6) of the NGPA requires that the Commission compute and make available maximum lawful prices and inflation adjustments at least five days before the beginning of any month for which such figures apply. Pursuant to that mandate, the Commission hereby amends its interim regulations implementing the NGPA to add to the existing price tables, prices and inflation adjustments for the months of February, March, and April 1979.

The Commission has received many comments through its written comment procedures, toll-free telephone inquiry line, and NGPA Implementation Seminars regarding pricing and filing requirements relating to minimum rate gas as defined in § 271.402(b)(a) of the interim regulations. Prices applicable to minimum rate gas were included in §§ 271.101(a) and 271.402(a) which set forth maximum ceiling prices prescribed under sections 104 and 106(a) of the NGPA for natural gas committed or dedicated to interstate commerce as of November 8, 1978. Final regulations issued by the Commission on November 17, 1978 (43 FR 55756, November 29, 1978), and amended by the Commission on December 28, 1978 (44 FR 1100, January 4, 1979) established filing requirements for collection of those prices. In response to comments received on pricing and filing, the Commission has decided to amend these regulations to restate the price for minimum rate gas and to insure that collection of that price is subject to the mandatory blanket affidavit filing requirements imposed in § 154.94(h).

B. SUMMARY OF AMENDED REGULATIONS

The interim regulations are being modified to include the maximum lawful prices and inflation adjustments for February, March, and April 1979. The subparts of Part 271 of Subchapter H of the interim regulations so affected, and the types of natural gas to which these subparts apply, are as follows: Subpart A—Summary Tables and Caculations (§§ 271.101(a) and 271.102(c)); Subpart B—New Natural Gas and Certain Natural Gas Produced from the Outer Continental Shelf (§ 271.202); Subpart C—New, Onshore Production Wells (§ 271.302); Subpart D—Natural Gas Committed or Dedicated to Interstate Commerce (§ 271.402(a)); Subpart F—Intrastate Rollover Contracts (§ 271.602); Subpart G—High-Cost Natural Gas (§ 271.702); Subpart H—Stripper Well Natural Gas (§ 271.802); and Subpart I—Other Categories of Natural Gas (§ 271.902). Further, Part 273 of Subchapter H is amended by adding the maximum lawful prices for February, March, and April 1979 to Subpart B—Interim Collection Authority (§ 273.201(a)(1)).

The interim regulations are also being amended to express the price for minimum rate gas in terms of Mcf's rather than MMBtu's. This modification is necessary because the April 20, 1977, minimum rate of 18.0 cents per Mcf established in § 2.56b(b) of this chapter is not subject to an adjustment for Btu content, unlike the other maximum lawful prices set forth in the tables in §§ 271.101(a) and 271.402(a). In order to correctly state the price for minimum rate gas, we shall remove the category "Minimum rate gas" from the tables in §§ 271.101(a) and 271.402(a) which list the maximum lawful prices for gas subject to the provisions of sections 104 and 106(a) of the NGPA and do so in terms of MMBtu's. A separate paragraph (c)(4) has been added to § 271.402 to indicate the price per Mcf to be charged under the NGPA for minimum rate gas in December 1978, and in January, February, March, and April 1979.[1]

A conforming amendment relating to minimum rate gas is required in § 154.94(h) of the final regulations setting forth the filing requirements for producers qualifying for a maximum lawful price under section 104(b)(1)(A) or 106(a) of the NGPA. Under § 154.94(h)(1), a producer is required to file a blanket affidavit under which he may collect the applicable maximum lawful price where he has established qualification for a base rate under the Natural Gas Act. One of the prerequisites for establishment of such base rate, as set forth in § 154.94(h)(2)(ii), is that the collection of the base rate be permissible under the applicable sales contract. However, application of this rule would exclude minimum rate gas from the blanket affidavit procedures because minimum rate gas is permitted to be sold at a rate in excess of the applicable sales contract rate. In order to make it clear that the blanket affidavit filing procedure applies to minimum rate gas, we shall amend § 154.94(h)(2)(ii) to provide an exception to the requirement that the collection of the base rate be permissible under the applicable sales contract, for minimum rate gas. Affidavits previously submitted which reflect the "Applicable NGPA Rate" for minimum rate gas in terms of a price per MMBtu need not be amended to reflect that such rate is a price per Mcf. The Commission will consider such previously submitted affidavits to conform with the amendments adopted herein.

C. COMMENT PROCEDURES

Although these amendments to the regulations are being issued effective immediately, interested persons are invited to submit written comments, data, views, or arguments with respect to this action. An original and 14 copies should be filed with the Secretary of the Commission. All comments received prior to March 1, 1979, will be considered by the Commission, and if appropriate, further revisions will be made. All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours. Comments should be submitted to the FERC, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should reference Docket Nos. RM79-3 and RM79-4.

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[1] For consistency with other NGPA prices, a producer may convert the price per Mcf to an MMBtu equivalent, if necessary.

D. EFFECTIVE DATE

The Commission is making these amendments effective upon the date of issuance of this order upon a finding that good cause exists to proceed without compliance with the notice, public procedure and effective date provisions of 5 U.S.C. 553. The NGPA requires that maximum lawful prices and inflation adjustments be made available at least five days before the beginning of the month to which they apply. Unless amendments regarding minimum rate gas are made effective immediately, and prior to the termination of the 60-day period for comments on the interim regulations, producers (most of whom bill in January for deliveries made in December) may bill and file incorrectly for minimum rate gas. Thus good cause exists to make all of these amendments effective upon issuance of this order.

(Natural Gas Act, as amended, (15 U.S.C. 717 *et seq.*), Energy Supply and Environmental Coordination Act, (15 U.S.C. 791, *et seq.*), Federal Energy Administration Act, (15 U.S.C. 761, *et seq.*), Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, Department of Energy Organization Act, Pub. L. 95-91, E. O. 12009, 42 F.R. 46267).)

In consideration of the foregoing, Part 154 of Subchapter E and Parts 271 and 273 of Subchapter H, Chapter I, Title 18, Code of Federal Regulations, are amended as set forth below, effective immediately.

By the Commission.

KENNETH F. PLUMB,
Secretary.

* * *

[FR Doc. 79-3097 Filed 1-29-79; 8:45 am]

[¶ 30,034]

44 F. R. 10366 (Feb. 20, 1979).

[Docket No. RM79-10]

PART 287—RULES GENERALLY APPLICABLE TO POWERPLANT AND INDUSTRIAL FUEL USE

FEBRUARY 9, 1979.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Interim rule.

SUMMARY: Section 103(a)(18)(D) of the Powerplant and Industrial Fuel Use Act of 1978 (Act) requires the Commission to promulgate rules under which a powerplant's design capacity may be determined. The definitions of design capacity will be used to determine the applicability of certain temporary and permanent exemptions under the Act. These regulations establish the interim rules under which a powerplant's design capacity may be determined.

DATES: Effective February 9, 1979; comments on or before March 19, 1979.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. (Reference Docket No. RM79-10.)

FOR FURTHER INFORMATION CONTACT:

Charles F. Reusch, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, 202-275-4216 or

B. E. Biggerstaff, Office of Electric Power Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, 202-275-4721.

SUPPLEMENTARY INFORMATION:

INTERIM RULE

On December 29, 1978, the Commission issued a Notice of Proposed Rulemaking with a comment period ending January 30, 1979. Pursuant thereto, notice is hereby given that Chapter I of Title 18, Code of Federal Regulations (CFR), is amended by adding a new Subchapter J, entitled Regulations Under the Powerplant and Industrial Fuel Use Act of 1978. A new § 287.101, under Subchapter J establishes methods for determining powerplant design capacity. This regulation is promulgated as an interim rule. Additional comments are invited and will be accepted through March 19, 1979.

BACKGROUND

Section 103(a)(18)(D) of the Powerplant and Industrial Fuel Use Act of 1978 (Act), Pub. L. 95-620, requires the Federal Energy Regulatory Commission (Commission) to promulgate, by February 9, 1979, rules under which a powerplant's design capacity may be determined. The determination of a powerplant's design capacity is necessary because it is an element of each of the statutory definitions of the terms "peak load powerplant," "intermediate load powerplant," and "base load powerplant" as provided in section 103(a)(18) of the Act. The definitions of those terms will be used to determine the applicability of certain temporary and permanent exemptions from sections 201 and 202 of the Act. Sections 201 and 202 proscribe the use of natural gas or petroleum as a primary energy source in new electric powerplants. The aforementioned exemptions are found in sections 212(g) and 212(h) of the Act. The definitions are also to be used to determine the applicability of certain temporary and permanent exemptions from sections 301 and 302 of the Act, relating to existing electric powerplants, pursuant to sections 311(f), 312(f), and 312(g) of the Act. Finally, determinations regarding design capacity are necessary under section 501 of the Act, entitled Electric Utility System Compliance Option, in order to determine if existing electric utilities are in compliance with Title III of the Act.

SUMMARY OF COMMENTS SUBMITTED TO DATE

Substantive comments were received from 13 parties concerning the proposed rulemaking. In summary, they expressed the following views:

1. Three parties proposed the use of demonstrated actual capability rather than maximum generator nameplate rating in defining design capacity.

2. Four parties agreed with the use of the nameplate rating system but suggested that the definitions be made more flexible to provide for (a) unit modifications, or (b) instances where the nameplate rating is so different from actual operating capabilities as to be totally inaccurate.

3. One comment noted the difference between nameplate rating and actual operating capability but made no recommendation as to which value to use.

4. One comment proposed that the nameplate rating should be based on unity power factor.

5. One comment agreed with the use of a nameplate rating but suggested that the rating for a combustion turbine used as part of a combined cycle unit should be based on the combustion turbine's baseload, rather than peak load, using American National Standards Institute (ANSI) and International Standards Organization (ISO) standard condition ratings.

6. One comment noted that the regulation should specify the units in which the nameplate rating shall be stated.

7. Another suggested that the reference to "combustion turbine" does not follow the Act's use of "gas turbine", and in so doing does not follow the intent of the law.

8. Finally, two comments protested the short period between notice in the FEDERAL REGISTER and the due date for comments. The Commission responds to the final point as discussed below in *Public Comment Procedures.*

The Act, at section 103(a)(18)(D), without further explanation or clarification, requires this Commission to "prescribe the rules under which a powerplant's design capacity may be determined." A manufacturer's initial design of a unit is planned so as to attain a specific capability under specified standardized operating conditions. The manufacturers design each unit to achieve a capacity indicated as a nameplate rating. During its useful life a unit may be, for any of a number of reasons, redesigned, and accordingly, modified so as to achieve a capacity level other than that which was initially designed. Operating capability is a utility's determination of the output from a generating unit which it considers can be achieved with high probability under the existing conditions.

In developing the proposed regulations the Commission recognized the existence of a number of powerplant capacity ratings used by the electric power industry, most of which are used for operational purposes. While operational figures may be indicative of a powerplant's ability to produce electric power, using such fluctuating ratings for the purposes of monitoring fuel use compliance under the Act creates an unnecessarily heavy administrative burden. The burden arises because a powerplant's operating capability constantly changes in that it is a function of ambient weather conditions, systems operating conditions, unit degradation and other factors. None of these factors is relevant in determining whether a powerplant qualifies as a peakload, intermediate or baseload powerplant. Adopting operating capability as the basis for design capacity rating would result in a powerplant's design capacity rating changing from year-to-year, or season-to-season. Such a rating would be difficult to monitor for purposes of the Act. Weighing that administrative burden against the fact that the differential between operating capability and a manufacturer's nameplate rating is relatively insignificant, nameplate rating has been adopted in the interim rule as a standard for determining the powerplant's design capacity.

Some of the comments suggested that a mechanism be adopted whereby a powerplant's design capacity rating (initial or modified) could be changed when the powerplant is physically and substantially modified or when a unit is operating subject to some permanent governmental restraint which affects its design capacity.[1] Since additional comments are requested on this interim rule, the Commission specifically invites further comments on this issue. The Commission also welcomes discussion on the following questions:

(1) Should a powerplant's design capacity be modified each time the powerplant is physically and substantially modified? Should it also be modified whenever permanent governmental restraints are imposed on the powerplant which, in effect, alter the design capacity? If so, what sort of modification or restraints would result in a change in design capacity and how should such changes be noticed? [2]

(2) Should the modified design capacity be determined by actual demonstrated tests reflecting the continuous capacity of the powerplant during the utility's peakload season?

(3) Where and when should notification of such changes be filed? Should notification be filed with the Energy Information Administration (EIA), the Economic Regulatory Administration, or with the Commission? Should such notification be filed before or at the time of modification or imposition of the restraint, whenever possible; thirty days afterwards; or at the same time as other forms presently filed with Department of Energy, are filed, specifically those forms presently designated as FPC Form 1, FPC Form 4, and FPC Form 12?

(4) Should the notification certify the following information:

(a) The original nameplate rating;

(b) The nature of the modification or restraint; and

(c) The modified design capacity as it is determined pursuant to the actual demonstrated tests?

What other information should be submitted?

(5) Should the modified design capacity be effective immediately upon filing an affidavit or upon approval by the reviewing administration or commission? Should the owner or operator be allowed to appeal a determination of the reviewing administration or commission?

Information received in response to these questions will aid the Commission in determining whether a mechanism for modification should be adopted. If the Commission determines that such a mechanism should be adopted the information provided should further aid the Commission in formulating that part of the final rule.

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[1] The preamble to the Notice of Proposed Rulemaking issued December 29, 1978, noted that a powerplant's design capacity may change when a powerplant is physically modified but failed to incorporate a provision for changing the nameplate rating.

[2] As contemplated by the Commission, modifications of design capacity would result from the following situations, for example:

(1) Installation of certain larger auxiliary equipment that increase the capacity of the powerplant; and (2) imposition by the federal or local government of regulations to eliminate excessive emissions of air or water pollutants which preclude a powerplant from operating at full capacity.

The Commission does not adopt the suggestion that design capacity should be based on nameplate figures at unity power factor. Neither power systems nor individual generating units normally operate at unity power factor, thus the suggestion is unrealistic and therfore is rejected.

The suggestion that the combustion turbine portion of combined cycle units be rated on baseload ANSI/ISO standard conditioning rating is adopted in this rule, since combined cycle units will generally be operated as intermediate load powerplants rather than peakload powerplants. We accept this proposal and have so revised the rule.

The Commission agrees that the regulation should specify the units in which the nameplate rating shall be stated and has provided that capacity ratings shall be measured in kilowatts. We do not agree that use of the term "combustion turbine" rather than "gas turbine" will result in deviation from the intent of the Act since the terms are generally interchangeable within the electric power industry.

SUMMARY OF THE RULE

The interim rule is summarized below:

(1) The design capacity of a steam-electric generating unit shall initially be its maximum generator nameplate rating, measured in kilowatts, which has been reported to the Energy Information Administration on EIA Form——(formerly FPC Form 12).

(a) The design capacity of a combustion turbine shall be its peak load rating, measured in kilowatts, as defined by both the American National Standards Institute and by the International Standards Organization. ANSI/ISO peak load rating is based on units operating for peaking service at a maximum of 2,000 hous per year at an ambient temperature of 59 degrees Fahrenheit (15 degrees Celsius) and a pressure of 14.696 psia (sea level). This should be the capacity rating reported to the Energy Information administration on EIA Form——(formerly FPC Form 12). While ANSI/ISO peak load rating may be based on units operating at 2,000 hours per year or less, a powerplant may not qualify as a peakload powerplant except as defined in section 103(a)(18)(A) of the Act. If those reported ratings are based on different conditions, they will be adjusted to ISO Standard conditions for the purposes of the Act.

(3) The design capacity, measured in kilowatts, of a combined cycle unit shall be the sum of its combustion turbine base load rating, based on ANSI/ISO standard conditions, and the maximum generator nameplate rating of the steam turbine portion of the unit, as reported in EIA Form——(formerly FPC Form 12).

(4) The design capacity of an internal combustion engine shall be the capacity rating in kilowatts which has been reported to the Energy Information Administration on EIA Form——(formerly FPC Form 12).

PUBLIC COMMENT PROCEDURES

The proposed rule issued December 29, 1978, was not published in the FEDERAL REGISTER until January 22, 1979 (44 FR 4500). Parties dependent on the FEDERAL REGISTER for notification inadvertently were allowed only eight days for submission of comments on the proposed rule. Since the Act requires the Commission to promulgate a rule under which a powerplant's design capacity may be determined by February 9, 1979, the Commission will issue this rule as an interim rule effective immediately.

The Commission recognizes that the eight day FEDERAL REGISTER notice did not provide adequate notice for public participation. Therefore, this rule is issued as an interim regulation and comments will be accepted through close of business on March 19, 1979. If the additional comments received convinced the Commission that amendments to this rule are appropriate they will be issued in the final rule. If no amendments are adopted this rule will become effective as a final rule and such notice will be published in the FEDERAL REGISTER. Comments received regarding the proposed rulemaking will be retained and considered during consideration of the interim rule.

Interested persons may submit comments concerning this interim rule by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before March 19, 1979. Each person submitting a comment should include his name and address, identify the notice (Docket No. RM79-10), and give reasons for any recommendations. An original and 14 conformed copies should be filed with the Secretary of the Commission. Comments should indicate the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be adressed. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours.

Comments which have been received thus far even if they were received after the January 30 deadline will be retained and reviewed with any comments received pursuant to this notice.

(Department of Energy Organization Act, Pub. L. 95-91; E.O. 12009, 42 F.R. 46267; Powerplant and Industrial Fuel Use Act of 1978, Pub. L. 95-620.)

In consideration of the foregoing, the Commission amends Chapter I of Title 18, Code of Federal Regulations, as set forth below.

By the Commission.

KENNETH F. PLUMB,
Secretary.

[FR Doc. 79-5191 Filed 2-16-79; 8:45 am]

[¶ 30,035]

44 F. R. 12406 (Mar. 7, 1979).

[Docket No. RM79-20]

CERTAIN SALES OF NATURAL GAS BY INTRASTATE PIPELINES

MARCH 1, 1979.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final regulations.

SUMMARY: The Federal Energy Regulatory Commission is amending its regulations by adding to Part 284 a new Subpart C permitting intrastate pipelines to sell natural gas to interstate pipelines and to local distribution companies served by interstate pipelines, in accordance with the provision of the subpart. This rulemaking implements section 311(b) of the Natural Gas Policy Act of 1978. These amendments also conform the table of Parts for Subchapter I to reflect these and other recent amendments to Subchapter I, and incorporates the NGPA's definitions for all terms defined in the NGPA.

EFFECTIVE DATE: March 1, 1979.

FOR FURTHER INFORMATION CONTACT:

Kenneth F. Plumb, Secretary, Federal Energy Regulatory Commission, 825 North Capitol St., NE., Washington, D.C. 20426 (202) 275-4166.

SUPPLEMENTARY INFORMATION

I. BACKGROUND

Section 311(b) of the Natural Gas Policy Act of 1978 (NGPA), Pub. L. 95-621, November 9, 1978, provides that the Federal Energy Regulatory Commission (Commission) may, by rule or order, authorize any intrastate pipeline to sell natural gas to any interstate pipeline and any local distribution company served by an interstate pipeline. Section 311(b) also sets forth certain requirements relating to rates and charges, duration and other matters in connection with the sales, and states that sales authorized under section 311(b) are subject to such other terms and conditions as the Commission may prescribe.

On November 13, 1978, the Commission adopted a notice of proposed rulemaking (43 FR 53270, November 15, 1978) in Docket No. RM79-3, proposing interim regulations to implement the NGPA. In that document, the Commission requested comments on proposed regulations implementing section 311(b). Although most of the regulations in that proposal were to become effective on December 1, 1978, the Commission proposed not to make Subpart C of Part 284, implementing section 311(b), effective until after the current winter heating season. The purpose of delaying the effectiveness of the section 311(b) rule was to permit a transition from the Commission's emergency exemption program under section 7(c) of the Natural Gas Act, to implementation of the NGPA provisions permitting sales by intrastate pipelines to interstate pipelines and local distribution companies.

On February 5, 1979, the Commission issued a Further Notice of Proposed Rulemaking and Public Hearing (44 FR 7976, February 8, 1979) which proposed a new Subpart C and requested further data, views and comments with respect to the implementation of section 311(b) and also invited participation in a public hearing on the proposal. The public hearing was held on February 23, 1979, at which five persons testified, representing pipeline companies, an electric utility and the State of Louisiana. Twenty-three comments were received. Several suggestions contained in the comments have been incorporated into the final rule.

This rule shall become effective March 1, 1979.

II. Discussion of Comments

1. *What is the appropriate period for determining "weighted average acquisition cost of natural gas"?* Many parties commented on the proposed rule which would have based the determination of weighted average acquisition costs on the basis of volumes acquired over a 12-month period. No party agreed with the proposal and several presented arguments as to why the proposal should not be accepted.[1] The most commonly stated reason was that the proposal failed to permit the intrastate pipeline to recover actual and contemporaneous costs of gas associated with 311(b) sales. The Conference Report on the NGPA, S. Rep. No. 94-1126, 94th Cong., 2nd Sess. (1978), at page 108, states that:

> * * * weighted average acquisition cost is meant to be a contemporaneous determination. It is not based upon an historical cost which may have been lower. Instead, it is intended to look to the cost of the gas at the time is acquired and resold.

Upon review of the comments received and the arguments presented, the Commission believes that the proposal of February 5 should be modifed to more accurately reflect the Congressional policy quoted above. The final rule provides that "weighted average acquisition cost" will be based upon "the most recent calendar month for which data are available prior to the first day of the billing period in which deliveries pursuant to the sale occur and for which deliveries the weighted average acquisition cost is to be charged."

The Commission is aware that many interstate pipelines and local distribution companies who would be qualified to purchase natural gas under this program may have particular tariff provisions or requirements of state regulation which do not permit rate adjustments rapidly enough to provide the requisite revenues at the end of the billing period as may be necessary to meet the charges by the selling intrastate pipeline. This would be exacerbated by a methodology which provided for billing based upon actual purchase volumes and actual weighted average acquisition cost experienced for the billing period. Consequently, the Commission has imposed a condition in § 284.145(d) that the purchaser be notified of the rate to be charged under § 284.144 at least five (5) days prior to the beginning of each billing period.

The final rule's method for determination of weighted average acquired costs, with the adjustments permitted in § 284.144(a)(2) is deemed to be an acceptable method for calculation, but it is not mandatory. Parties to a sale, for example, may agree to a method of calculation and billing for the recovery of the cost of gas which is based on the method we noticed on February 5, 1979. However, no method may result in a per unit charge for the cost of gas delivered during any billing period which exceeds the unit cost for such deliveries as would be calculated under the method prescribed in § 284.144(a)(1) and (2).

2. *Should the Commission's existing regulations covering emergency transactions be retained?* Rules implementing provisions for emergency transactions under the Natural Gas Act were issued with the Interim Regulations

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[1] We note, however, that Oklahoma Natural Gas Company proposed a similar methodology in its comments filed on November 20, 1978, in response to the November 13, 1978 notice.

Implementing the Natural Gas Policy Act of 1978, Subpart C of Part 157, Title 18, Code of Federal Regulations. The rules issued on December 1, 1978, advised the public that the emergency provisions under the Natural Gas Act might be terminated after March 1, 1979. Several parties have argued against the revocation of the emergency provisions. The Commission will not act at this time to revoke them. They will remain effective until the Commission takes further action to modify them in a separate rulemaking, to be announced at a later date. The Commission intends to carefully analyze and compare the scope of Part 157 and Part 284 to make sure that all necessary emergency transactions are permitted to take place. After this analysis the Commission will revise Subpart C of Part 157 to cover emergency transactions not covered under Part 284 of the Regulations and which the Commission concludes are necessary to continue. Consequently, the regulations currently contained in Part 157 of the Commission's regulations remain effective until further action of the Commission.

3. *Should the Commission modify the language of the rule to clarify its policy such that natural gas which is purchased to meet reasonably projected needs shall not be considered to be acquired primarily for resale pursuant to section 311(b)?* Three parties suggested that § 284.145(c) may be read to technically prohibit sales which section 311(b) was intended to permit. Section 311(b)(7)(B) provides that the Commission shall disapprove any transaction which involves, "the sale of natural gas acquired by the intrastate pipeline involved solely or primarily for the purpose of resale of such natural gas pursuant to (section 311(b))(1)." The Conference Report clarifies the intent of Congress by explaining at page 109 that:

> [g]as that is determined by the Commission to be reasonably projected to be necessary to meet an intrastate pipeline's future market and buyer requirements shall not be considered by the Commission to be solely or primarily acquired by the intrastate pipeline for the purchase and resale in the interstate market.

The proposal in § 284.145(c) generally adopted the language in section 311(b)(7)(B). To avoid any confusion, the Commission has added to § 284.145(c) language which also generally follows the clarifying language in the Conference Report.

4. *Should the definition of "intrastate pipelines" be expanded to include the so-called "Hinshaw" pipelines?* Several parties commented on the fact that the definition of "intrastate pipelines" in section 2(6) of the NGPA does not include natural gas companies defined in section 1(c) of the Natural Gas Act (so-called Hinshaw pipelines). The language in section 2(16) of the NGPA and the importance of the resolution of this issue to the implementation of both Titles I and II of the NGPA requires that the Commission consider issues outside of the scope of these rules. Consequently, the Commission will consider and resolve the issue of the appropriate classification of pipelines not subject to the jurisdiction of the Commission by reason of section 1(c) of the Natural Gas Act in a separate proceeding which the Commission intends to address in the immediate future.

5. *What procedural requirements should govern proceedings to terminate sales under this subpart?* Two companies addressed the issue of procedural requirements for proceedings to terminate sales under this rule. One party stated that any such proceeding should involve an adjudicatory hearing. Another party stated that such a proceeding should be initiated only through informal hearings so that patently unwarranted complaints may be eliminated. Neither suggestion is adopted. The language in the proposal follows section 311(b)(6) of the NGPA. The Commission prefers to retain its discretion, to be exercised on a case-by-case basis, to establish appropriate procedures to determine whether a transaction should be terminated.

Such procedures may, in appropriate circumstances, include the use of either adjudicatory or informal hearings.

6. *Should reasonable profits be allowed on sale of natural gas by intrastate pipelines?* Two parties were concerned that the proposal did not provide for reasonable profits on the resale of the natural gas itself. The Conference Report, at page 108, specifically states that:

> [t]he conferees do not intend the selling pipeline to make a profit on the purchase and sale aspects of the transaction.

In compliance with Congressional policy, the rule will not permit reasonable profits on the resale of the gas by the intrastate pipeline. However, as pointed out below, an opportunity to earn a reasonable profit is permitted on those services enumerated in section 311(b)(2)(B) of the NGPA.

7. *Should the regulations specifically express the policy that the intrastate pipeline may earn a reasonable profit on expenses incurred in the process of providing gathering, treatment, processing, transportation, and delivery services?* The proposal provided for recovery of expenses incurred in the process of providing gathering, treating, processing, transporting and delivering natural gas and any profits as determined in accordance with § 284.123, but did not specifically state inclusion of an opportunity to earn a reasonable profit. To avoid any possible problems in the future with regard to this issue, the Commission has included in the final rule language which incorporates the provisions of section 311(b)(2)(B)(ii) which states that the Commission should permit the selling intrastate pipeline an opportunity to earn a reasonable profit on services described in section 311(b)(2)(B)(i).

8. *Should the "weighted average acquisition cost of natural gas" be based on the costs of system supply or the costs associated with specific contracts?* One party suggested that the language of the proposal be clarified so that the weighted average acquisition cost be determined by reference to only the specific contractual sources of supply from which the natural gas delivered under the sale is received. Section 311(b)(2)(C) provides for an adjustment to the fair and equitable price to compensate for any increase in the pipeline's weighted average acquisition cost of natural gas as the result of purchasing volumes in excess of those that would otherwise have been purchased under existing contracts. In order that section 311(b) transactions bear their fair share at the cost of any change in the weighted average acquisition cost of gas as the result of additional purchases under existing contracts in order to make the transactions, the methodology would permit the attribution of the cost of the additional purchases to the section 311(b) transaction. However, such an adjustment under section 311(b)(2)(C) is only available if the costs associated with the additional purchases of the natural gas for the 311(b) transaction results in an increase in the weighted average acquisition cost of natural gas to the intrastate pipeline's other customers.

9. *Should a rebuttable presumption in favor of extensions be created in § 284.146?* The Commission elects not to create a rebuttable presumption in favor of extensions. The Commission adopts the proposal which permits intrastate pipelines to continue sales pursuant to this rule without requiring further action by the Commission and, at the same time, protects the Commission's discretion to examine such extensions.

III. SUMMARY OF THE FINAL RULE

Subpart C of Part 284 permits intrastate pipelines to sell natural gas to interstate pipelines and to local distribution companies served by interstate pipelines, in accordance with its provisions. These sales may take place without prior Commission approval, but as required by section 311(b)(4) of the NGPA and § 284.145(b) of the regulations, are subject to interruption to the extent that natural gas subject to the sale is required by selling pipeline to provide adequate service to the pipeline's customers at the time of the sale. Upon complaint or its own motion, the Commission may terminate a sale after making certain findings enumerated in section 311(b)(6) of the NGPA.

Sales are limited to two years' duration under § 284.145(a) and can be extended for periods of up to two years each if not disapproved by the Commission after opportunity for oral and written comments. The Commission may modify the terms of a proposed extension and impose upon sales or extensions terms and conditions it deems appropriate and in the public interest.

Section 284.145(c) of the regulations states that no sales under Subpart C may involve natural gas acquired by the intrastate pipeline solely or primarily for the purpose of resale under section 311(b). It also states that the Commission shall consider whether the intrastate pipeline reasonably anticipated the needs of its future market in determining whether a sales contract was entered into solely or primarily for the purpose of resale under this rule.

Section 284.143 requires "weighted average billing cost of natural gas" to be determined according to the cost of system supply. For any billing period in which deliveries pursuant to this rule occur, the weighted average acquisition cost shall be computed by (1) determining the actual quantities of natural gas (expressed in terms of MMBtu's) purchased by the intrastate pipeline from each source of supply during the most recent calendar month for which data are available prior to the first day of the billing period in which deliveries pursuant to the sale are to occur and for which deliveries the weighted average acquisition cost is to be charged; (2) multiplying the MMBtu's attributable to each source of supply by the most recent price actually paid during the calendar month upon which the volumes are computed with respect to each source; and (3) dividing the sum of the products computed in (2) by the sum of the BBMtu's determined in (1). Thus, the calculation of the weighted average cost shall be determined in accordance with the most recent prices paid.

The intrastate pipeline's weighted average acquisition cost of natural gas is one of the three components of the permissible rates and charges for a sale under Subpart C. The pipeline may add, as provided in § 284.144(a)(2), an adjustment to reflect any difference between the weighted average acquisition cost of natural gas used for purposes of billing during the latest billing period and the actual weighted average acquisition cost experienced during the same billing period; plus, under § 284.144(a)(3) an amount to recover the costs of gathering, treating, processing, transporting and delivering the gas as provided in § 284.123 of Subpart B of Part 284 (Interim Regulations, 43 F.R. 56628-56629, December 1, 1978). Section 284.148(a)(4) requires the filing of the method to be followed in computing any unit cost difference between the weighted average acquisition cost used for billing period purposes and actual cost for the same billing period. Under § 284.123(b), an intrastate pipeline may base its rates upon the methodology and cost used (1) in designing its rates to recover the cost of gathering, treatment, processing, transportation, delivery or similar service (including storage) included in its firm sales rate schedules for city-gate service on file with a state regulatory agency; or (2) in determining the allowance permitted by an appropriate state regulatory agency for city-gate service by the intrastate pipeline. The pipeline may elect to use the rates contained in a transportation rate schedule for intrastate service on file with the state regulatory agency which the pipeline determines covers service comparable to service under Subpart B. Instead of any of these methods, an intrastate pipeline may file proposed rates with the Commission, with information showing the rates to be fair and equitable, and may commence service using those rates, subject to refund.

The third component of the rates and charges permissible in Subpart C sales is the adjustment described in section 311(b)(2)(C) of the NGPA and § 284.144(b) of the regulations. The adjustment is intended to offset any contemporaneous increase in the weighted average acquisition cost of natural gas that a pipeline would incur to acquire natural gas under existing contracts as a result of entering into sales under Subpart C. The adjustment may be included in the sales price with respect to natural gas which (1) is acquired under an existing contract; (2) is in excess of quantities the pipeline would otherwise have acquired; and (3) the price of which exceeds the pipeline's weighted average acquisition cost of natural gas. If natural gas meeting these criteria is sold pursuant to Subpart C, the pipeline may add to the basic rate an amount sufficient to offset the increase in its weighted average acquisition cost.

As discussed above, a condition was added in § 284.145(d) that the purchaser be notified of the rate to be charged under § 284.144 at least five (5) days prior to the beginning of each billing period.

The reporting requirements in § 284.148 include an initial report, to be filed within 60 days after commencing deliveries under a Subpart C sale and "subsequent reports" whenever a significant change occurs in the information submitted with the initial report. If an extension of the sale is sought, an extension report must be filed not less than 90 days prior to the expiration of the sale. The extension report consists of a current statement of the information required in the initial report and the terms of the proposed extension. Finally, within 60 days after termination of any sale or extension, a final report is required of the purchaser stating quantities purchased, amount paid and delivery points. All reports are required to be under oath, signed by a senior official of the company.

As announced in the November 13 and February 5 proposals, this rule shall become effective on March 1, 1979. The rule should be implemented as soon as possible in order that needed supplies of natural gas may reach the interstate market. Additionally, these provisions relieve any unnecessary restrictions against the sales permitted by this rule. It should also be noted that these regulations do not require any actions be taken. It merely permits parties to enter into transactions under these regulations.

Two additional amendments have been included in this rulemaking. The first merely conforms the table of Parts for Subchapter I to reflect this and other amendments that have recently been made in the Subchapter. The second incorporates at Part 280, for purposes of Subchapter I, the NGPA's definition for all terms defined in the NGPA.

(Natural Gas Policy Act of 1978, Pub. L. 95-621)

In consideration of the foregoing, the Commission amends Subchapter I, Part 284, Chapter I of Title 18, Code of Federal Regulations, as set forth below, effective March 1, 1979.

[¶ 30,036]

44 F. R. 13460 (Mar. 12, 1979).

[Docket No. RM78-23; Order No. 10-B]

PART 154—RATE SCHEDULES AND TARIFFS

Interstate Pipeline Recovery of State of Louisiana First Use Tax

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: This final rule amends the procedures, established in Order No. 10 (43 FR 45553, October 3, 1978), and No. 10-A (43 FR 45553, December 28, 1978) for recovery of the Louisiana First Use Tax by interstate natural gas pipelines. The rule sets forth the rate treatment and accounting procedures to be followed until a final and non-appealable court determination of the constitutionality of the Louisiana First Use Tax is made.

DATES: This final rule is effective as of March 2, 1979.

FOR FURTHER INFORMATION CONTACT:

William Topping, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426. Phone: 202-275-4822.

On August 28, 1978, the Commission issued Order No. 10[1] which amended § 154.38 of its regulations promulgated pursuant to the Natural Gas Act, by adding a new paragraph (18 CFR § 154.38(h)). On December 20, 1978 the Commission issued Order No. 10-A[2] which modified Order No. 10, amended paragraph (h), and requested comments. Paragraph (h), as amended, establishes procedures governing pipeline recovery of the State of Louisiana First Use Tax on Natural Gas.[3]

Under Paragraph (h), as amended by order No. 10-A, pipelines are permitted to collect the First Use Tax, subject to refund, pursuant to a temporary tracking mechanism similar to a purchased gas adjustment clause. In order to establish the tracking provision, pipelines are required to pay the First Use Tax under protest and to challenge the constitutionality of the tax by instituting an action for recovery of the amount paid under protest in accordance with La. Rev. Stat § 47: 1576. Paragraph (h) also requires that during the pendency of litigation, pipelines must hold in escrow all funds collected. If the First Use Tax is found unconstitutional by a final and non-appealable court order, pipeline customers would receive the escrowed funds plus earnings on those funds, and the pipelines would receive such amounts of tax payments plus interest as are refunded by the State of Louisiana. If the First Use Tax is found constitutional by a final and non-appealable court order, then the pipeline would receive the escrowed funds plus the earnings on those funds.

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[1] 43 FR 45553 (October 3, 1978) (The October 3rd FEDERAL REGISTER citation includes the August 28th Order as corrected by Errata notice of September 15, 1978).

[2] 43 FR 60438 (December 28, 1978).

[3] 1978 La. Sess. Law Serv. 482 (Act No. 294), to be codified as La. Rev. Stat. §§ 47:1301–47:1307. Hereinafter referred to as "First Use Tax."

Although Order N0.10-A was made effective upon issuance, the Commission solicited written comments from interested persons.[4] Included within several of these comments were applications for rehearing and reconsideration of Order No. 10-A.[5]

In response to the issues raised by the comments and applications for rehearing, the Commission is modifying Order No. 10-A and amending § 154.38. Order No. 10-A is being modified to allow pipelines to select either an escrow account procedure or a corporate undertaking procedure. A pipeline which selects the corporate undertaking procedure, however, must agree to certain conditions to protect the pipeline's customers' funds. These conditions will be discussed in detail below.

I. ISSUES

The comments and applications for rehearing generally raised three issues:[6]

(1) Whether the escrow account requirement is necessary if Louisiana law provides for recovery of all First Use Tax payments upon a final and non-appealable court determination that the tax is invalid.

(2) Whether Order No. 10-A unlawfully requires pipelines to bear the risk of loss in the event that the First Use Tax is determined to be invalid and the State of Louisiana fails to return all funds paid by the pipelines.

(3) Whether Order No. 10-A unlawfully deprives pipelines of their right to recover, pursuant to section 4 of the Natural Gas Act, interest costs associated with the First Use Tax.

II. ESTABLISHMENT OF THE CORPORATE UNDERTAKING PROCEDURE

The Commission in Order No. 10 and in Order No. 10-A concluded that "present Lousiana law may not permit pipelines to recover "all protested amounts paid."[7] The Commission determined that some additional procedures were necessary to protect pipeline customers' funds. The result was establishment of an escrow account which protects all funds collected from the pipelines customers.

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[4] The Commission has received comments from the Interstate Natural Gas Association of America (INGAA), Transcontinental Gas Pipe Line Corporation (Transco), Texas Gas Transmission Corporation (Texas Gas), Panhandle Eastern Pipe Line Company and Trunkline Gas Company (Panhandle), United Gas Pipe Line Company and Sea Robin Pipeline Company (United), Michigan Wisconsin Pipe Line Company (Michigan Wisconsin), Natural Gas Pipeline Company of America (Natural), Tennessee Gas Pipeline Company (Tennessee), Texas Eastern Transmission Corporation (Texas Eastern), Northern Natural Gas Company (Northern), Columbia Gas Transmission Corporation (Columbia), W. J. Tauzin, Louisiana House of Representatives, and William J. Guste, Jr., Attorney General, State of Louisiana.

[5] Transco, United, and Natural filed applications for rehearing and reconsideration of Order No. 10-A. On February 21, 1979 the Commission granted the pipelines' applications for rehearing of Order No. 10-A for the purpose of further consideration.

[6] See Section IV, Miscellaneous Comments, for additional issues which have been raised solely in the comments of one party.

[7] Order No. 10 at 2; Order No. 10-A at 9-12. This conclusion was supported by Tennessee Gas Pipeline in its Application for Rehearing of Order No. 10 p. 3. Tennessee stated that Louisiana's enactment of the First Use Tax Trust Fund (1978 La. Sess. Law Serv. 480 (Act No. 293), to be codified as La. Rev. Stat. § 47:1351), specifically La. Rev. Stat. § 47:1351(D), may have effectively repealed the protective escrow and refund provisions of La. Rev. Stat. § 47:1576. Tennessee concluded that "there is no assurance that the funds remaining in the escrow fund will be adequate to refund the total First Use Taxes paid." Although Tennessee filed comments on Order No. 10-A, it did not further discuss this conclusion.

Many of the comments filed by the pipelines suggested that the Commission was in error regarding its understanding of Louisiana law. Transco stated that the "State of Louisiana must refund any payments made under protest if the First Use Tax is ultimately determined to be unlawful, thus making the procedural devices prescribed in Order No. 10-A unnecessary." [8] Texas Gas stated *"There is no reasonable legal basis for this assumption."* [9] Michigan Wisconsin stated: "Michigan Wisconsin and its Louisiana counsel have studied the Louisiana statutes, * * * and believe that the State of Louisiana has an absolute obligation to refund all amounts of tax collected, if the tax is held invalid." [10] Several of the comments included legal opinions from various legal counsel from Louisiana that concluded that an adequate and complete remedy existed under Louisiana state law. [11] Furthermore, W. J. Tauzin, one of the authors of the First Use Tax legislation, and William J. Guste, Attorney General of the State of Louisiana, submitted comments stating that an adequate and complete remedy exists under Louisiana state law.

Although the opinions before us conclude that Louisiana would make full refunds, the Commission is constrained to conclude that there may not be an adequate remedy under Louisiana state law to permit pipelines to recover protested amounts paid if the First Use Tax is found unconstitutional. [12] However, since most of the pipelines believe that an adequate and complete remedy exists under Louisiana state law, the Commission has decided to modify Order No. 10-A, and to amend the regulation promulgated therein to allow pipelines to choose either the escrow account procedure or a corporate undertaking procedure.[13] Selection of the escrow account procedure or the corporate undertaking procedure will occur only at the time a pipeline applies for tracking of the First Use Tax, and after an initial selection of either method, a pipeline will not be permitted to change its selection.[14]

Under the corporate undertaking procedure a pipeline will be able to collect the tax, subject to refund, pursuant to the tracking mechanism established in Order Nos. 10 and 10-A, if the pipeline complies with the following conditions which have been established to protect the pipeline customers' funds:

(1) A pipeline *voluntarily* agrees to refund, within 60 days of the issuance of a final and non-appealable court order, those payments made on that portion of the First Use Tax found to be invalid, together with corresponding interest at the refund interest rate under Louisiana law, but not less than 6%. A pipeline voluntarily makes this agreement even if the State of Louisiana does not refund those funds plus interest to the pipeline.

(2) A pipeline shall take all legal action necessary to enforce contract provisions which could required the other contracting party to pay the First Use Tax. Since most pipelines have emphatically stated that Louisiana must refund all payments made under protest if the First Use Tax is ultimately determined to be unlawful, most pipelines should have no prob-

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[8] Transco, Application for Rehearing and Reconsideration of Order No. 10-A at p. 2.

[9] Order No. 10-A Comments of Texas Gas Transmission Corporation at p. 2.

[10] Michigan Wisconsin, Comments at p. 4.

[11] Transco received a legal opinion from the law firm of Oliver & Wilson; Texas Gas received a legal opinion from the law firm of Jones, Walker *et al.*, and Southern Natural Gas Company received a legal opinion from Liskow & Lewis. All three are law firms practicing in Louisiana.

[12] We do not denigrate the legal opinions on this matter which have been placed in the record of this proceeding. We simply conclude that these opinions do not definitively answer the question of whether there is an adequate remedy at state law, and that, given the substantial sums involved, additional procedures are required to ensure that interstate consumers will receive full and prompt refunds if the law is found unconstitutional.

[13] Several pipelines, including Tennessee, Natural Michigan Wisconsin, and Texas Gas stated that a corporate undertaking would adequately protect the pipeline customers' funds.

[14] See Section VI, *infra*, for a discussion of the filing dates for tracking and selection of procedures.

lem accepting and complying with the first condition.[15]

Further, although Order No. 10-A required pipelines to pay the First Use Tax under protest and to challenge the constitutionality of the tax by instituting an action for recovery of the amount paid under protest in accordance with La. Rev. Stat. § 47:1576, it was silent as to other legal remedies available to the pipelines to decrease their liability for the First Use Tax. Numerous contracts to which pipelines are a party contain provisions which could require the producer or gatherer selling natural gas to an interstate pipeline to pay the First Use Tax.[16] For example, it appears that in 15% of the cases the producer is still the owner at the processing stage,[17] and is, therefore, potentially liable for the First Use Tax.[18] In many other cases, the contract may require the producer or gatherer selling natural gas to an interstate pipeline to reimburse the pipeline for all costs (including any taxes) incurred as a result of extracting natural gas liquids; again, absent § 47: 1303: C.,[19] the producer may be liable for the First Use Tax imposed for any "Use" which occurs as a result of such processing.[20] A pipeline would be imprudent if it did not assert its legal rights through enforcement of its contracts. The Commission therefore finds the second condition appropriate for the corporate undertaking procedure, and will also adopt it as a condition for the escrow account procedure.

III. RETENTION OF THE ESCROW ACCOUNT PROCEDURE

For those pipelines which do not believe that Louisiana law provides a complete and adequate remedy at law for recovery of the First Use Tax, the

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[15] In *City of Cleveland, Ohio* v. *FPC*, 525 F. 2d 845, 850 footnote 37 (D.C. Cir. 1976) the Court of Appeals for the District of Columbia Circuit allowed full recovery of taxes paid, even if the tax could not be recovered in full from the state, because the company agreed to make a full refund.

[16] Many of these contracts have been incorporated into certificates of public convenience and necessity issued by this Commission and the Federal Power Commission.

While the Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat 3350, eliminates the requirement that producers obtain certificates for sale of natural gas which was not committed or dedicated to interstate commerce on or before the date of enactment (NGPA § 601(a)(1)(A)) and removes certain classes of committed or dedicated gas from the regulatory structure of the Natural Gas Act (NGPA § 601(a)(1)(B)), many existing sales of natural gas, which are subject to the First Use Tax, remain subject to the regulatory structure of the Natural Gas Act, which provides in Section 7, 15 U.S.C. § 717f, that the contracts and certificates for such sales may not be amended without prior Commission approval. Furthermore, under the NGPA, the Commission has the authority to determine whether costs of processing natural gas to remove liquids may be recovered from the purchasers of the processed gas and passed on to consumers. NGPA § 110(a)(2).

[17] Representative Tauzin, Verbatim Draft Transcript of Hearing on the First Use Tax before the Senate Revenue and Fiscal Affairs Committee on June 26, 1978 at 3.

[18] The First Use Tax provides that "Use" is defined as (§ 47:1302(8)):

The sale; the transportation in [Louisiana] to the point of delivery at the inlet of any processing plant; the transportation in [Louisiana] of unprocessed natural gas to the point of delivery at the inlet of any measurement of storage facility; transfer of possession or relinguishment of control at a delivery point in [Louisiana]; processing for the extraction of liquifiable component products or waste materials; use in manufacturing; treatment; or other ascertainable action at a point within [Louisiana].

The First Use Tax further provides that it is "deemed a cost associated with uses made by the owner in preparation of marketing of the natural gas." § 47: 1303: C.

[19] La. Rev. Stat. § 47: 1303: C. provides in pertinent part:

Any agreement or contract by which an owner of natural gas at the time a taxable first use occurs claims a right to reimbursement of refund of such taxes from any other party in interest, other than a purchaser of such natural gas, is hereby declared to be against public policy and unenforceable to that extent.

[20] In this proceeding, the Commission, although it doubts the validity of the First Use Tax, is not attempting to determine the validity of that statute; it is merely requiring the pipelines to take all legal action necessary to enforce contract provisions which could require the other contracting party to pay the First Use Tax. This requirement does not contradict the above provisions of the First Use Tax, but simply protects the contractual rights of the pipelines and their customers while the constitutionality of the First Use Tax is being contested.

Commission is retaining the escrow account as an alternative to the corporate undertaking. The Commission has decided to modify the escrow account procedure to include the same "legal action" language as adopted in the undertaking procedure. Under this new requirement, a pipeline is required to take all legal action necessary to enforce contract provisions which could require the other contracting party to pay the First Use Tax.

Many comments attempted to distinguish the cases which were cited in Order No. 10-A [21] to support the Commission's determination that the ratepayers should not bear the cost of a tax which is ultimately found to be unconstitutional. Legal precedent, including the cases cited in Order 10-A, support the Commission's conclusion that the pipeline customers should not bear the cost of an unconstitutional tax which is unrecoverable from the taxing state.

Many of the comments suggested that, under the escrow procedure of Order No. 10-A, pipelines would be subject to potential losses because the cost of borrowing money would not be offset by the interest accrued in the escrow fund [22] or by the interest refunded from Louisiana.[23] The Commission agrees that the costs of borrowing will possibly not be completely offset. It is unclear, however, to what extent pipelines will incur losses. The Comments by Northern briefly discusses the impact of the Federal income tax deduction on interest paid on amounts borrowed to pay the First Use Tax. The Federal income tax deduction apparently decreases the potential losses of a pipeline.[24] Michigan Wisconsin suggests that, through litigation, Louisiana's 6% interest rate on refunds could possibly be increased.[25] This would also decrease any potential losses by a pipeline. The Commission therefore defers any determination on this issue until the conclusion of litigation when the Commission will be able to determine more accurately the interaction of various variables which could affect any possible losses by the pipelines through their borrowing of funds. The Commission however, does want to make clear, that at the time it does make its determination on this issue, it may find that any losses are properly allocated to the stockholders of the pipelines.

IV. MISCELLANEOUS COMMENTS

Tennessee requests that the tracking provisions of Order No. 10-A be modified to provide continuation of the tracking of the First Use Tax beyond a final court determination and until the pipeline's next general section 4 rate increase takes effect. The Commission shall deny Tennessee's request. At the time a pipeline's tracking provision terminates pursuant to the provisions of this order, a pipeline is free to make a general section 4 rate filing if it believes that termination of the tracking provision will cause the pipeline to earn less than a just and reasonable rate of return on its jurisdictional business.

> Michigan Wisconsin requests: a waiver of Order No. 10-A, or an authorization in the Regulations to deviate from April 1 as a "first adjustment" date, to the extent necessary to allow Michigan Wisconsin to eliminate the April 1 interim rate adjustment and simply have its first rate increase be effective on May 1, 1979, which pursuant to the tracker, would recover 13 months of estimated tax payments over the succeeding 12-month period.[26]

The Commission will accept Michigan Wisconsin's request, but Michigan Wisconsin will not be allowed carrying charges on any deferred collection of the First Use Tax.

Michigan Wisconsin also requests that a provision be added to the regulation allowing pipelines to collect from their customers any attorney fee charges which Louisiana may force the pipelines to pay if the pipelines contest the First Use Tax and it is ultimately found constitutional. In a recent decision, *South Central Bell Telephone Company* v. *Traigle,*[27] The Louisiana Supreme Court held that an additional 10% of that portion of a contested tax which is held valid would be assessed against a taxpayer who paid the tax under protest in accordance with La. Rev. Stat. § 47:1576.[28] Michigan Wisconsin notes that "[T]he attorney fees will not be paid over [the collection] period, but only (if at all) at the end of the litigation * * *"[29] The Commission therefore defers any determination on this issue until the end of litigation, at which time the Commission will be able to make its decision in light of the actual details of a Louisiana court opinion. The Commission does want to make clear, that at the time it does make its determination on this issue, the Commission may find that the 10% lawyer fee charge is properly allocated to the stockholders of the pipelines.

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[21] See Order No. 10-A mimeo p. 8-9. The cases cited were *NAACP* v. *FPC*, 425 U.S. 662, 666 (1976); *Tennessee Natural Gas Line, Inc.* v. *FPC*, 221 F.2d 531 (D.C. Cir. 1954); *City of Cleveland, Ohio* v. *FPC*, 525 F.2d 345, 850 (D.C. Cir. 1976); *Panhandle Eastern Pipe Line Co.*, 13 F.P.C. 53, 103 (1954); and *El Paso Natural Gas Co.* 13 F.P.C. 421, 436 (1954).

[22] Order No. 10-A stated that if the First Use Tax were found valid, the First Use Tax payments and the costs of borrowing would "[B]e offset by the funds in the escrow account plus the earnings on those funds." Mimeo p. 20.

[23] Order No. 10-A stated that if the First Use Tax was found invalid, "The interest refunded by the State of Louisiana will offset costs of borrowing money." Mimeo p. 28.

[24] Northern Comments at p. 7 footnote 1.

[25] Michigan Wisconsin, Comments at p. 5.

[26] Michigan Wisconsin, Comments at p. 9.

V. Filing Dates

Order No. 10-A required pipelines to submit applications for tracking on or before March 1, 1979. Since the tracking provisions have not been modified in this order, pipelines should not need additional time to file the tracking provisions. However, the Commission is modifying the March 1 filing date and is allowing pipelines to file their applications for tracking on or before March 15, 1979. Pipelines will also be required to make their selection of the escrow account procedure or the corporate undertaking procedure on or before March 15, 1979. Two weeks should be a sufficient time to make a selection.

Order No. 10-A required the establishment of an escrow agreement but did not establish a date for the submission of this agreement or for the submission of a certificate attesting to the fact that an agreement had been executed.[30] Pipelines which select the escrow account procedure shall submit these documents on or before March 15, 1979. Pipelines which select the corporate undertaking procedure shall submit an undertaking, as established in this order, on or before March 15, 1979.

VI. Summary

For the reasons stated above, Order No. 10-A is modified in response to the applications for rehearing of Order No. 10-A and the comments on Order No. 10—A. The applications for rehearing are denied except as provided in this order. Since this order responds to the issues raised in the comments and the applications for rehearing, the Commission denies the request by the Interstate Natural Gas Association of America for oral argument.

VII. Effective Date

The Commission is making these amendments effective upon the date of issuance of this order upon a finding that good cause exists to proceed without compliance with the effective date provisions of 5 U.S.C. 553. On April 1, 1979, pipelines become subject to the First Use Tax. Before pipelines can reflect the First Use Tax in their rates, pipelines must submit applications for tracking the tax, select either the escrow procedure or the corporate undertaking procedure, and the Commission must review these trackers to ensure that they comply with this regulation. Since the regulation must be effective within sufficient time for the Commission's analysis to occur, the Commission finds that good cause exists to make these amendments effective upon issuance of this order.

VIII. Findings

(1) The Commission's prior orders, Order Nos. 10 and 10-A, should be

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[27] Case No. 62011, Supreme Court of Louisiana on certiorari to the Court of Appeal, First Circuit, East Baton Rouge Parish, Louisiana, December 15, 1978.

[28] The Supreme Court relied on its interpretation of La. Rev. Stat. § 47:1512 which states:

"The collector is authorized to employ private counsel to assist in the collection of any taxes, penalties or interest due under this Sub-title, or to represent him in any proceeding under this Sub-title. If any taxes, penalties or interest due under this title are referred to an attorney at law for collection, an additional charge for attorney fees, in the amount of ten per centum (10%) of the taxes, penalties and interest due, shall be paid by the tax debtor.

[29] Michigan Wisconisn Comments at p. 8.

[30] See 18 CFR 250.12.

clarified and amended consistent with this order.

(2) Oral argument would not be of benefit to this Commission in its determination of this rule.

(3) Good cause exists to allow waiver of the first adjustment date for Michigan Wisconsin, and to allow Michigan Wisconsin to have its first rate increase effective May 1, 1979, with recovery of 13 months of tax payments over the succeeding 12-month period.

(4) In view of the purpose, intent, and effect of the amendments, good cause exists for making them effective as of the date of issuance of this order.

(Natural Gas Act (15 U.S.C. 717 c, f, o); Administrative Procedure Act (5 U.S.C. 553); Department of Energy Organization Act, (42 U.S.C. 7101, *et seq.*); and E.O. 12009, (42 FR 46267))

In consideration of the foregoing, the Commission hereby orders that:

(A) Except as provided in this order, the applications for rehearing filed by all parties in this proceeding are denied;

(B) The request for oral argument by the Interstate Natural Gas Association of America is denied;

(C) The Commission's Order Nos. 10 and 10-A are clarified and amended consistent with this order;

(D) Waiver of this first adjustment date of § 154.38(h) is granted for Michigan Wisconsin to the extent necessary to allow Michigan Wisconsin to have its first rate increase effective May 1, 1979, with recovery of 13 months of tax payments over the succeeding 12-month period. Michigan Wisconsin will not be allowed carrying charges on any deferred collection of the First Use Tax.

(E) Waiver of the notice requirements for the initial filing is granted.

(F) Part 154, Chapter I of Title 18, The Code and Federal Regulations, is amended as set forth below, to become effective as of the date of issuance of this order.

[¶ 30.037]

44 F. R. 13473 (Mar. 12, 1979).

[Docket No. RM79-9]

PART 286—ADMINISTRATIVE PROCEDURES

Final Regulations Providing For Stay of Final or Interim Rules Issued Under the NGPA

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Amendment to a Final Rule.

SUMMARY: The Federal Energy Regulatory Commission is amending its final rule which provided a procedure for stay of interim regulations promulgated pursuant to the Natural Gas Policy Act of 1978 (NGPA). The amendment expands the rule so that it will encompass applications for stay of final rules issued pursuant to the NGPA.

EFFECTIVE DATE: March 2, 1979.

FOR FURTHER INFORMATION CONTACT:

Alexander M. Peters, Office of the General Counsel, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 275-4311.

BACKGROUND

On December 4, 1978, the Federal Energy Regulatory Commission (Commission) promulgated a rule, Docket No. RM79-9, which provided a procedure for stays of interim regulations promulgated pursuant to the Natural Gas Policy Act of 1978 (NGPA) 43 FR 57598 (December 8, 1978). While some of the regulations promulgated pursuant to the NGPA remain as interim rules, the Commission has begun promulgation of final rules under the NGPA. The Commission believes the stay procedure should be applicable to final rules, as well as interim rules. Accordingly, the Commission is amending its regulations governing stay procedures so that they are applicable to final rules.

FINDINGS AND CONCLUSIONS

The Commission has determined that the amendment to the regulation should be effective immediately. Inasmuch as the regulation is procedural, the requirement for notice, comment and publication 30 days prior to the effective date does not apply. The final regulation is effective March 1, 1979, without prior notice and comment and without publication 30 days prior to the effective date.

(Administrative Procedure Act, 5 U.S.C. 551 *et seq.*, Natural Gas Policy Act of 1978, Pub. L. 95-621, Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267.)

Part 286, Subchapter I of Chapter I of Title 18, Code of Federal Regulations, is amended as set forth below.

[¶ 30,038]

44 F. R. 13464 (March 12, 1979).

[Docket No. RM79-13]

PART 281—NATURAL GAS CURTAILMENT

Interim Curtailment Rule

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Promulgation of an Interim Curtailment Rule.

SUMMARY: The Federal Energy Regulatory Commission is promulgating an interim natural gas curtailment rule in order to implement section 401 of the Natural Gas Policy Act of 1978 (NGPA). The rule is applicable to natural gas delivered for the period April 1, 1979 through October 31, 1979. Interstate pipelines are required to adjust their curtailment plans, to the maximum extent practicable, in order to prevent curtailment of deliveries of natural gas for essential agricultural uses or for high-priority uses.

EFFECTIVE DATE: April 1, 1979.

FOR FURTHER INFORMATION CONTACT:

MaryJane Reynolds, Office of the General Counsel, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 275-4331.

SUPPLEMENTARY INFORMATION:

A. BACKGROUND

On January 10, 1979, the Federal Energy Regulatory Commission (Commission) issued a Notice of Proposed Rulemaking wherein an interim curtailment rule was proposed pursuant to section 401 of the NGPA. A hearing was held in Washington, D.C. on the proposed rule on January 26, 1979. The Commission is in this order issuing its final Interim Curtailment Rule.

Section 401 of the NGPA seeks to assure that natural gas required for essential agricultural uses will not be curtailed unless curtailment is necessary to protect the needs of certain high-priority users. Section 401 requires the interaction of three agencies of the Federal Government: the Department of Energy (DOE), the Department of Agriculture (USDA), and the Commission.

Section 401(a) provides that not later than 120 days after the date of enactment of the NGPA the Secretary of Energy shall prescribe and make effective a rule which provides that no curtailment plan of an interstate pipeline may provide for curtailment of deliveries of natural gas for any of the enumerated high-priority and essential agricultural users. Section 401(c) states that the Secretary of Agriculture shall certify to the Secretary of Energy and to the Commission the natural gas requirements for essential agricultural uses in order to meet the requirements of full food and fiber production. The Secretary of Agriculture transmitted his rule containing this certification to the Commission on February 27, 1979.

The Commission must implement those rules so that, to the maximum extent practicable, no curtailment plan of an interstate pipeline results in curtailment of deliveries of natural gas for any essential agricultural use, unless such curtailment does not reduce the quantity of natural gas delivered for such use below the use requirement specified by the Secretary of Agriculture or such curtailment is necessary in order to meet the requirements of high-priority users, as that term is defined in section 401(f)(2) of the NGPA.

THE AGRICULTURE RULE

By a rule effective March 1, 1979, the Secretary of Agriculture certified to the Secretary of Energy and the Commission the natural gas requirements of essential agricultural uses in order to meet the requirements of full food and fiber production (7 CFR Part 2900). The agriculture rule is designated as an interim rule, to be superseded by a permanent rule upon the publication by the USDA of a Final Environmental Impact Statement.

Section 401(c) of NGPA directs the Secretary of Agriculture to certify to the Secretary of Energy and the Commission either persons or classes of essential agricultural users. The Secretary of Agriculture has elected to certify classes of essential agricultural uses, designated by utilization of Standard Industrial Code (SIC) classifications.

Similarly, pursuant to section 401(c) of NGPA, the Secretary of Agriculture must certify use requirements for natural gas, either as volumes or percentages of use. The Secretary has generally chosen to certify percentages of use rather than designating specific volumes for each such user.

The requirements of essential agricultural users which utilize natural gas on-farm for agricultural production or which consume 300 Mcf or less of natural gas on a peak day were certified by the Secretary of Agriculture to be 100% of current requirements. The requirements of other essential agricultural users were certified to be the highest actual volume of natural gas used during the applicable period of the most recent three years (updated annually) which has the highest corrected volume. Use volumes would be corrected to include amounts of process and feedstock gas not used because of curtailment or plant shutdown. Alternatively, the certified volumetric requirement would be the maximum volume of gas the user would be entitled to purchase under the interstate pipeline's curtailment plan in effect on March 1, 1979, if these volumes are higher than the corrected volumes determined under the three-year rule.

The agriculture rule also permits an essential agricultural user limited to the higher of its highest gas use for the most recent three-year period (corrected as indicated above) or its curtailment plan entitlement, to seek an exception from the Secretary of Agriculture if the process and feedstock requirements of the user exceed the computed volume by twenty-five percent or more. Finally, the agriculture rule states that the volumetric requirements of essential agricultural users certified by the Secretary of Agriculture are not necessarily limited to the maximum contracted volume of the user.

B. SUMMARY OF COMMENTS AND OF REVISIONS OF COMMISSION RULE

On January 10, 1979, the Commission issued its notice of proposed rulemaking to implement section 401 on an interim basis. The Commission determined to issue an interim rule terminating on October 31, 1979 because implementation of the rule on a permanent basis will require data collection during the summer of 1979.

During the interim period each interstate natural gas pipeline will, where necessary, provide relief from curtailment to high-priority users and essential agricultural users in accordance with a new tariff provision which this rule directs that the pipeline file. This tariff provision is analogous to the existing life and property tariff provisions that pipelines have filed pursuant to 18 CFR 2.78(a)(4) of the Commission's rules of practice and procedure. This emergency relief mechanism has in the past been used to grant relief from curtailment which would have resulted in danger to life, health, and physical property. In drafting the present rule, the Commission drew on this experience so that during this interim period, interstate pipelines may provide relief from curtailment to high-priority users and essential agricultural users under a mechanism with which they are familiar and which they have successfully utilized in the past. Tariff sheets filed by pipelines to implement the interim rule may incorporate by reference appropriate provisions of the interim rule.

Section 4 of the Natural Gas Act requires interstate pipelines to file tariff sheets reflecting any change in their curtailment plans. In compliance with the direction of Congress to carry out the intent expressed in section 401 to the "maximum extent practicable" (section 401(a)), the Commission has determined to make the rule effective April 1, 1979, rather than March 9, 1979. The April 1, 1979 effective date of the interim rule is required to provide adequate time for submission of tariff sheets, comment, and analysis and action upon the tendered tariff sheets.

The rule proposed for comment reflected the initial proposal of the Secretary of Agriculture and the perceived need to apply an alternative fuel test in a reasonably practicable manner. The Interim Final Rule of the Department of Agriculture is different from that initial USDA proposal with respect to certification of volumetric requirements. The Commission has been impressed by the many comments it received to the effect that the initial proposal by the Commission would not take account of the impacts of past curtailments and that it failed to reflect Congressional intent with respect to evaluation of the economic practicability and reasonable availability of alternative fuels. Therefore, the final rule incorporates by reference the Secretary of Agriculture's certifications. The Commission believes that this change brings into harmony the various rules required to implement section 401 for the interim period.

Under our January 10, 1979 notice of the proposed rule, the maximum volume of gas which could be delivered to the essential agricultural user was the lesser of the volumes the user would receive under the presently effective curtailment plan or the user's highest volume of gas in calendar years 1976, 1977 and 1978. There were many comments to the effect that the proposed rule would not take into account the possibility that an agricultural user of natural gas might have been curtailed in the past and enforced to resort to fuel that did not meet the alternative fuel test established in section 401. There are also comments respecting a conflict among USDA and Commission resposibilities. These issues have been resolved in the interim final rule by referencing the Secretary of Agriculture's certification.

Interstate pipelines are required to meet the supply deficiencies of essential agricultural users up to the lesser of the amount of the volumetric requirement certified by the Secretary of Agriculture or the amount of natural gas the pipeline is obligated to supply under the applicable contract between the pipeline and the customer. For customers served by a local distribution company the local distribution company may call upon their interstate pipeline suppliers to meet supply deficiencies of essential agricultural users up to the lesser of the volumetric requirements certified by the Secretary of Agriculture or the total obligation specified in the contract between the local distribution company and the pipeline. For a customer served by more than one interstate pipeline, the deficiencies will be served in proportion to deliveries by those pipelines in the corresponding period of 1978.

The contractual entitlement for an essential agricultural user shall not be diminished because the essential agricultural user's contract with its direct interstate pipeline supplier is on an interruptible basis or because all or part of the local distributor's contract with any of its interstate pipeline suppliers is on an interruptible basis.

An essential agricultural user will first evaluate the volume of natural gas it estimates the user will require for high-priority users and essential agricultural uses for a particular curtailment period and will subtract from those requirements its available gas supply from all sources, including intrastate and self-help sources available to serve such uses for the same period. If the available supply for a particular curtailment period is less than the requirements for that period, the high-priority user or essential agricultural user can attribute the deficiency to its direct suppliers by dividing (i) the volume such direct supplier supplied to the eligible end-user for the corresponding curtailment period of 1978 by (ii) the sum of the volumes supplied the user by all such direct suppliers during the curtailmant period.

The local distribution company shall make the computation for residential and small commercial customers and attribute deficiencies among its direct interstate pipeline suppliers. The local distribution company shall utilize the same method of attribution as described above for its other high-priority uses and essential agricultural uses. To the extent that supply increases, it is the responsibility of the end-user or the local distribution company to recalculate the supply deficiency.

Interstate pipelines will receive requests for adjustments of curtailment levels from their direct sale customers or their local distribution companies on behalf of high-priority users or essential agricultural users in order to correct supply deficiencies. Interstate pipelines, subject to certain exceptions, are instructed to grant the adjustments up to the lesser of the supply deficiency or the supply obligation. The interstate pipeline's supply obligation to direct high-priority users is limited to the high-priority users' requirements in the presently effective curtailment plan of the interstate pipeline. The interstate pipeline's supply obligation to direct essential agricultural users is limited to the requirements certified by the Secretary of Agriculture as long as those requirements do not cause a direct end-user to exceed its contractual entitlement with the interstate pipeline or a local distribution company to exceed its contractual entitlement with the interstate pipeline. In either case, contract entitlement would be determined without regard to contract conditions which permit deliveries to be interrupted under certain circumstances.

An interstate pipeline will reduce volumes delivered under an adjustment when (1) the reduction in deliveries necessary to effect the adjustment would cause the curtailment of another essential agricultural user or high-priority user, or (2) the adjustment would reduce injection into storage by the interstate pipeline or any of its customers except to the extent that the Commission determines upon complaint that the storage is not necessary to serve high-priority uses and essential agricultural uses. No adjustment may be granted if the interstate pipeline's records contain information which conflicts with statements of the local distribution company or direct sale customer.

The limitations on adjustments to curtailment plans which would reduce deliveries to essential agricultural users or high-priority users reflect the statutory mandate in section 401(a). The provisions that adjustments be altered if they would reduce pipeline or customer storage for high-priority or agricultural uses reflects the DOE Rule and is in response to the comments of numerous pipelines concerned with the normal filling of storage reservoirs during the summer season.

The Commission's rule provides filing requirements to insure that the interstate pipeline will have sufficient data to examine when it considers the request for waiver. The subsequent notice of adjustments by the Commission will insure that all customers and the Commission staff will be able to analyze whether the adjustment complies with this rule.

The proposed interim rule provided for remedy if the Commission determined that a willful and knowing violation of the regulations took place. The final interim rule more closely tracks the Natural Gas Act by providing for a remedy whenever the Commission determines that a violation of this regulation has occurred. Since the tariff filing contemplated herein is pursuant to section 4 of the Natural Gas Act, remedial action pursuant to section 20 of the Natural Gas Act can be initiated upon potential violation of the Natural Gas Act. The question of knowledge and belief is a matter for a trier of fact.

Some comments argued that the proposed termination date should be eliminated so that if the permanent rule is not promulgated by the intended date, this rule would continue. The Commission has decided not to accept this suggestion. In connection with the proposed permanent rule for implementation of section 401, RM79-15, the Commission asked whether the proposed effective date should be postponed. Should it be decided in that proceeding not to implement the permanent rule on November 1, 1979, the Commission will then address the question of what interim curtailment arrangements should be used to implement section 401 beyond the scheduled termination date of this rule.

This decision to retain a fixed expiration date reflects Commission concern that the interim rule promulgated herein, while adequate for the next summer season, might not be adequate during next winter's heating season. Should the Commission decide not to implement the permanent rule by November 1, 1979, or if it is not possible, as now planned, to implement the permanent rule on certain pipeline systems, it might be reasonable to extend the effectiveness of this rule with appropriate modifications; alternatively it might be preferable to develop a different interim procedure. When and if it becomes necessary to re-examine this issue, the Commission will reopen this proceeding or hold a new proceeding to determine a rule for the next winter heating season. However, that issue is at best premature and may never arise.

This interim rule is a contingency plan. It will only come into effect if there is a threat of curtailment of a high-priority user or an essential agricultural user. If a distributor or an interstate natural gas pipeline, as appropriate, can serve the agricultural or high-priority requirements there will be no need to request relief under this rule. If gas supplies are as now anticipated, they should be sufficient so that agricultural requirements can be met without the need to resort to the provisions of this rule for relief. The agricultural sector consumes large volumes of natural gas during the summer period. If the gas supply and demand balance should be different than anticipated, the provisions of this rule will be available to protect essential agricultural users from curtailment.

The Commission agrees with the many commentators who emphasized that the agricultural sector is dynamic and its needs for natural gas are constantly shifting. The agricultural community has been subject to curtailments in the past but, even so, it has been able to increase production. The Commission intends that its section 401 program, consisting of several components of which this rule is one, provide access to natural gas supplies adequate to assure that agriculture continues to be able to expand its productivity. The Commission's proposed direct purchase plan for agricultural users, Docket No. RM79-18, would, if adopted, insure the availability of natural gas for new or expanded uses of natural gas.

A major issue attendant to implementation of the USDA, DOE rule, Commission interim and Commission permanent rules pursuant to section 401 is what provision, if any, should be made for agricultural load-growth. The Secretary of Agriculture's rule certifying essential agricultural use of natural gas, which is embodied in this rule, permits certain types of load-growth. The Commission's rule reflects its present belief that the USDA definition represents a reasonable resolution of the load-growth issue for the period April 1, 1979 to November 1, 1979. The Commission in its rule has removed any impediment, under interstate pipeline curtailment plans, to receipt of the certificated volumes. However, volumetric limitations in contracts between interstate pipelines and their direct customers or local distribution companies remain applicable (but without regard to certain contract provisions permitting interruptions by the pipeline). Certification requirements under section 7 of the Natural Gas Act, of course, remain unaffected. Moreover, the Commission recognizes that the amount, if any, of load-growth which should be permitted is a vital issue in the ongoing rulemaking for the permanent rule under section 401. By its action in this interim rule the Commission does not intend to prejudge the result for the permanent rule.

Many comments in this proceeding argued that Congress intended that all essential agricultural users on USDA's list shall have access to natural gas from interstate pipelines at rolled-in prices to meet all requirements. Those advancing this interpretation of section 401 would not distinguish among demands of long-established users, new demands, expanded demands, requirements currently being met by intrastate pipelines, requirements met by direct purchases or any other type of agricultural requirement.

Other comments, however, assert that section 401 does not provide for unlimited agricultural access to pipeline system supplies. It has been pointed out that section 401(a) specifies what a "curtailment plan of an interstate pipeline" may not do.

The legislative history is cited by some commentators as pertinent here. The House provision as originally passed stated that the specification of essential agricultural uses "may allow for additional amounts necessary in cases in which production capacities are expanded or in cases in which new production facilities are added." A comparable provision in the bill passed by the Senate stated that the requirement of essential agricultural uses would apply "(for present or expanded capacity) and new plants." As finally enacted into law the purpose of this section is to insure full food and fiber production, however, the bill contains no comparable provision allowing for the expanded uses or new uses of natural gas.

Another reason advanced in some comments for believing that Congress did not intend such expansion of access is its instructions about limiting revisions of pipeline curtailment plans and avoiding updating base periods. Section 401 of NGPA appears to contemplate revision of curtailment priorities within presently effective curtailment plans. The Congress was cognizant of the potentially disruptive effect on curtailment plans of a major shift in curtailment policy and thus the conference report states:

> For purposes of implementing this section, the Commission is instructed to reopen curtailment plans that are already in effect under the Natural Gas Act only to the extent necessary to adjust those plans to bring them into conformity with the new curtailment priority schedule. The conferees were concerned that these changes not burden the Commission with lengthy proceedings which might throw existing curtailment plans into disarray. Therefore, the conference agreement includes the term "to the maximum extent practicable" to assure that the Commission has the necessary flexibility in implementing any changes. For example, the conferees do not intend the reopening of curtailment plans for this limited purpose to result in adoption of a new base year for curtailment purposes.[1]

Some comments hold that to reflect requirements of all agricultural uses that are not presently included in pipeline curtailment plans would seem to require some reopening of those plans. These parties contend that the legislative history indicates that this was not the intent of Congress. Additionally, section 605 of the Public Utility Regulatory Policies Act of 1978 (PURPA), which requires that revisions in base periods not penalize local distribution companies by reducing these requirements where the reduction is due to conservation measures, was cited. The joint statement report on this section states:

> A change in a curtailment plan which does not require an updating of the base period data, such as the revisions required in Title IV of the Natural Gas Policy Act of 1978 would not trigger the application of this section.

Another troublesome question concerns the Natural Gas Act requirement that curtailment plans be found to be just and reasonable. One party contended that a curtailment plan giving some users 100 percent of current requirements while others were held to some fixed volume would be unduly preferential the thus would not satisfy this standard.

One comment asserted that elimination of base periods for agriculture would result in substantial shifts in the consumption pattern to natural gas. It cited a report which found that in SIC Code 20, food and kindred products, 28.9 million barrels of fuel oil and 3.3 million tons of coal were used. It was asserted that elimination of base periods for agriculture could result in these needs being shifted to natural gas which would not only adversely affect existing natural gas users but substantially increase the overall demand for natural gas and result in deepening curtailments.

Most interstate pipelines curtail according to base period data collected in the past. These base periods have not been updated and thus do not reflect new customers, attrition, conservation, or any other changes that may have occurred since the close of the base period. Nevertheless, many local distribution companies have been attaching new customers, in several end-use categories, for some time. The additional customers are not reflected in interstate pipeline curtailment plans, thus their needs have been served by local distribution companies out of their own sources of supply. There are numerous impacts possible from including these consumers in pipeline base period data.

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[1] S. Rep. 95-1126, 95th Cong. 2d Sess. 113.

The Commission recognizes that this is a vital issue, particularly in the permanent rule and intends to address the controversy in that proceeding. In that connection, the Commission will reconsider the comments on this matter provided in this docket. Parties may submit additional data, views and arguments on this issue in the proceedings on the permanent rule, if they wish.

The comments of certain pipelines suggested that an exemption from the filing of the tariff provision contemplated herein be included in the rule. Such an exemption provision is not necessary. Section 502(c) of the NGPA and the Commission's regulations under the Natural Gas Act provides the mechanism for such a waiver request. Any requests by pipelines for waiver of the filing of the tariff provision should be accompanied by a filing of the tariff provision.

Pursuant to § 154.51 the Commission has determined that good cause exists to waive § 154.22 of the Commission regulations to permit the filing of tariff sheets to become effective with less than 30 days' notice.

C. Section-by-Section Summary of the Interim Rule

The Commission's interim rule adds a new Part 281, Subpart A, to the Commission's rules and regulations under Title 18 of the Code of Federal Regulations.

PURPOSE (§ 281.101)

This section states that it is the purpose of the new Subpart A of Part 281 to provide that the curtailment plans of interstate pipelines do not, to the maximum extent practicable, cause curtailment of deliveries of natural gas for essential agricultural uses and for high-priority uses.

PPLICABILITY (§ 281.102)

Section 281.102 provides that subpart A applies to deliveries during the period April 1, 1979, through October 31, 1979, of natural gas sold by an interstate pipeline, if the pipeline is curtailing its deliveries of natural gas to direct sales customers or local distribution companies to such an extent that the direct sales customers or indirect sales customers are experiencing or will experience a supply deficiency for high-priority uses or essential agricultural uses.

DEFINITIONS (§ 281.103)

This section defines terms used in subpart A. The following definitions are included:

"Eligible end-user" is defined as a high-priority user or an essential agricultural user.

"Essential agricultural use" is defined as any use of natural gas which is certified by the Secretary of Agriculture as an "essential agricultural use" under section 401(c) of the NGPA, as identified in 7 CFR Parts 2900 *et. seq.*

"Essential agricultural user" is a person who uses natural gas for an essential agricultural use.

"High-priority use" is any use of natural gas which qualifies the user as a high-priority user.

"High-priority user" means any person who uses natural gas in a residence, in a small commercial establishment, in a school or a hospital, or for minimum plant protection when operations are shut down, for police protection, for fire protection, in a sanitation facility, or for certain other emergency situations. This definition is identical to that in the DOE rule.

"Indirect sale customer" of an interstate pipeline means an eligible end-user served by a local distribution company served by an interstate pipeline.

This section also defines "curtailment period," "direct sale customer," "residence," "small commercial establishment," "hospital," "school," and "local distribution company."

TARIFF FILING REQUIREMENTS (§ 281.104)

Section 281.104 requires interstate pipelines to file tariff sheets which allow for the granting of adjustments to the otherwise applicable provisions of their curtailment plans to carry out the new subpart A. The tariff sheets must be filed not later than march 16, 1979, with a proposed effective date of April 1, 1979.

ADJUSTMENT: GENERAL RULE (§ 281.105)

Section 281.105(a) authorizes a direct sale customer to request an adjustment from each of its direct interstate pipeline suppliers to satisfy its direct supply deficiencies for essential agricultural uses and high-priority uses. Subject to the limits of § 281.108, the interstate pipeline must adjust its currently effective curtailment plan to provide for delivery to the direct sale customer of volumes of natural gas which do not exceed the lesser of the direct supply deficiency or the direct supply obligation. The rules for determining supply deficiency and supply obligation are found in §§281.106 and 281.107, respectively.

Under § 281.105(b), an indirect sale customer (other than a residential user or a small commercial establishment may ask each of its local distribution company suppliers to request an adjustment from each of the interstate pipeline suppliers of such local distribution company to satisfy the indirect sale customer's indirect supply deficiencies (attributed to each of its interstate pipeline suppliers in accordance with § 281.106(e)). Subject to § 281.108, the local distribution company may receive an adjustment in the currently effective curtailment plan of each of its interstate pipeline suppliers providing for delivery to the local distribution company of volumes of natural gas which do not exceed the lesser of the aggregate attributed indirect supply deficiencies of all of these indirect customers or the pipeline's indirect supply obligation on account of these customers.

A local distribution company may under § 281.105(c) request an adjustment from each of its direct interstate pipeline suppliers to satisfy the indirect supply deficiencies of its residential and small commercial establishment customers for high-priority uses. Subject to § 281.108, each such interstate pipeline shall adjust its currently effective curtailment plan to provide for delivery to the local distribution company of volumes of natural gas which do not exceed the lesser of the sum of the indirect supply deficiencies of such customers or the pipeline's indirect supply obligations with respect to such customers.

Finally, provision is made for recalculation of supply deficiency, if there is a significant change in the supplies available to a direct sales customer or local distribution company.

CALCULATION OF SUPPLY DEFICIENCIES (§ 281.106)

Section 281.106 sets forth the method by which the various supply deficiency calculations are made by eligible end-users and by local distribution companies.

END USERS

Under paragraph (b) of this section, an eligible end-user computes its total supply deficiency as (i) the estimated volume of natural gas required by the eligible end-user for a particular curtailment period to satisfy such users high-priority uses or its essential agricultural uses, minus (ii) the estimated volume of natural gas available to the eligible end-user from all sources and for the same period to meet its high-priority uses and essential agricultural uses. Eligible end-users attribute their total supply deficiency in accordance with § 281.106(e) among all interstate pipeline direct suppliers and its local distribution company direct suppliers. Direct supply deficiency is that part of the total deficiency attributed to an interstate pipeline direct supplier. Indirect supply deficiency is that part of the total deficiency attributable to a local distribution company direct supplier. (See below for explanation of attributable indirect deficiency).

LOCAL DISTRIBUTION COMPANIES

Under paragraph (c), a local distribution company computes a total supply deficiency for all its residential and small commercial customers as the volume of natural gas the residential and small commercial customers will require, for a particular curtailment period, to satisfy residential and small commercial uses, minus the volume of natural gas the local distribution company estimates it will deliver to such eligible end-users in the same period. Local distribution companies attribute total supply deficiencies for these customers in accordance with § 281.106(e) among all its interstate pipeline direct suppliers. An indirect supply deficiency for residential and small commercial uses is the deficiency so attributed to a particular direct interstate pipeline.

Under § 281.106(c)(2), a local distribution company attributes the indirect supply deficiencies of each of its eligible end-users among all the interstate pipelines which are direct suppliers of the local distribution company. The attributable indirect supply deficiency of an interstate pipeline is the indirect supply deficiency of an eligible end-user attributed to that pipeline.

ATTRIBUTION

Section 281.106(e) contains the rules for attribution of supply deficiencies to particular suppliers. If an eligible end-user (other than a residential user or a small commercial establishment) receives natural gas from more than one direct supplier (that is, directly from more than one interstate pipeline or local distribution company served by an interstate pipeline), the fraction of such end-user's total supply deficiency attributable to each such direct supplier shall be determined by dividing (i) the volume such direct supplier supplied to the eligible end-user for the corresponding curtailment period of 1978 by (ii) the sum of the volumes supplied by all such direct suppliers of the eligible end-user during that curtailment period. If a local distribution company is directly supplied by more than one direct supplier, the fraction of the total supply deficiency for its residential and small commercial users and the indirect supply deficiency of its eligible end-users which is attributable to a particular direct supplier shall be determined by dividing (i) the volume such direct supplier supplied during the corresponding curtailment period of 1978 by (ii) the sum of the volumes supplied by all direct suppliers to the local distribution company during that curtailment period.

CALCULATION OF SUPPLY OBLIGATIONS BY INTERSTATE PIPELINES (§ 281.107)

Section 281.107 sets forth the method by which an interstate pipeline calculates its direct and indirect supply obligations.

HIGH-PRIORITY SUPPLY OBLIGATION

Direct high-priority supply obligation, calculated by an interstate pipeline for a curtailment period with respect to a direct sale customer, is equal to the maximum volume of natural gas the direct sale customer would be entitled to purchase for high-priority use under that interstate pipeline's currently effective curtailment plan.

Indirect high-priority supply obligation, calculated by an interstate pipeline for a curtailment period with respect to all high-priority users which are direct customers of a local distribution company, is equal to the maximum volume of natural gas that the local distribution company would be entitled to purchase under the pipeline's currently effective curtailment plan on account of all the high-priority uses of such customers to the extent such uses were part of the local distributions company's requirements included in such curtailment plan.

ESSENTIAL AGRICULTURAL SUPPLY OBLIGATION

(1) *Direct.* The direct essential agricultural supply obligation of an interstate pipeline for a curtailment period with respect to an essential agricultural user which is a direct sale customer is lesser of:

(i) The volume certified by the Secretary of Agriculture as essential agricultural volumetric requirements and calculated under 7 CFR 2900.4; or

(ii) The volume which may be delivered by the interstate pipeline to the direct sale customer without causing the interstate pipeline to violate any provision in any contract to which the interstate pipeline is a party, except those contract provisions which may otherwise restrict delivery because of supply or capacity shortage of the interstate pipeline.

(2) *Indirect.* The indirect essential agricultural supply obligation of interstate pipeline for a curtailment period to a local distribution company with respect to all essential agricultural users which are direct customers of the local distribution company is the lesser of:

(i) The sum of the volumes certified by the Secretary of Agriculture as essential agricultural volumetric requirements for all such essential agricultural users calculated under 7 CFR 2900.4; or

(ii) The volumes which may be delivered by the interstate pipeline to the local distribution company without causing the interstate pipeline to violate any provision of any contract to which the interstate pipeline is a party, except those contract provisions which may otherwise restrict delivery because of supply shortage or capacity of the interstate pipeline.

ADJUSTMENTS BY INTERSTATE PIPELINES (§ 281.108)

This section provides that where an adjustment is granted under this subpart, the interstate pipeline will deliver the volumes determined under § 281.105, from system supplies. Deliveries are to be reduced upon recalculation of supply deficiency under § 281.106(f).

Paragraphs (b) and (c) contain limits on the pipeline's obligation to make deliveries pursuant to adjustments. Pipelines must reduce volumes delivered under adjustments, in an equitable manner, in certain cases where such adjustments would otherwise result in (1) a direct or indirect supply deficiency; (2) a downstream interstate pipeline's inability to meet direct and indirect high-priority supply obligations; or reduction of deliveries reasonably necessary for injection into storage by the interstate pipeline or by any of its customers (except where such storage is not reasonably necessary to serve high-priority uses or essential agricultural uses).

Paragraph (c) deals with inconsistent information in pipeline records.

FILINGS AND NOTICE (§ 281.109)

This section contains filing requirements for end-users, local distribution companies, and interstate pipelines.

NOTICE, COMPLAINT AND REMEDY (§ 281.110)

This section contains procedures by which direct sales customer or local distribution company may file a complaint, and obtain remedy, of a violation of this subpart.

EXTRAORDINARY RELIEF (§ 281.111)

Under this section, an end-user or other person may obtain extraordinary relief under the Commission's existing rules.

(Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.;* Public Utility Regulatory Policies Act of 1978, Pub. L. 95-617; Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 stat. 3350; Department of Energy Organization Act, Public Law 95-91, E. O. 12009, 42 FR 46267.)

In consideration of the foregoing, Part 281, Subpart A, Subchapter I, Chapter I of Title 18, Code of Federal Regulations, shall read as set forth below.

By the Commission.

KENNETH F. PLUMB,
Secretary.

[¶ 30,039]

44 F. R. 16371 (March 19, 1979);
44 F. R. 20077 (April 4, 1979).

[Docket No. RM79-11]

PART 35—FILING OF RATE SCHEDULES

Change in Notice Requirements

JANUARY 2, 1979.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Commission amends its regulations under the Federal Power Act to require that changes in existing rate schedules and initial rate schedules be filed not less than sixty days or more than one hundred-twenty days before the change is to become effective. The change is required by the Public Utility Regulatory Policies Act of 1978.

EFFECTIVE DATE: January 2, 1979.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 (Reference Docket No. RM79-11).

FOR FURTHER INFORMATION CONTACT:

John O'Sullivan, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 (202) 275-4224.

SUPPLEMENTARY INFORMATION: The Federal Energy Regulatory Commission (the Commission) gives notice of amendments to §§ 35.2 and 35.3 relating to the filing of rate schedules and notification of filing deficiencies. Prior to these amendments, § 35.3 required that changes in existing rate schedules and initial rate schedules be filed not less than thirty days nor more than ninety days before the change was to become effective. This amendment changes the filing period to not less than sixty days nor more than one hundred-twenty days before the change is to become effective. In addition, paragraph (b) of § 35.3 is changed so that rate schedules based on the construction of facilities may be filed no earlier than one hundred-twenty days before they are to become effective. Section 35.2(c) required the Director of the Office of Electric Power Regulation to notify the filing utility of any deficiency in the filing within thirty days of its filing. This amendment changes the notification period to sixty days.

BACKGROUND

Section 207(a) of the Public Utility Regulatory Policies Act of 1978 (PURPA) Pub. L. 95-617, . amends section 205(d) of the Federal Power Act (16 U.S.C. 824(d)) so as to replace the word "thirty", wherever it appears, with the word "sixty". As amended, section 205(d) reads:

> (d) Unless the Commission otherwise orders, no change shall be made by any public utility in any such rates, charges, classification, or service, or in any rule, regulation, or contract relating thereto, except after sixty days' notice to the Commission and to the public. Such notice shall be given by filing with the Commission and keeping open for public inspection new schedules stating plainly the change or changes to be made in the schedule or schedules then in force and the time when the change or changes will go into effect. The Commission, for good cause shown, may allow changes to take effect without requiring the sixty days' notice herein provided for by an order specifying the changes so to be made and the time when they shall take effect and the manner in which they shall be filed and published. (49 Stat. 851-852; 16 U.S.C. 824(d))

As paragraph (a) of § 35.3 read prior to the amendment, all rate schedules or any part thereof were to be tendered for filing with the Commission and posted not less than thirty nor more than ninety days prior to the date on which the rate or service was to become effective. The regulation established a sixty-day period within which new or amended rate schedules were to be tendered to the Commission. In order to conform § 35.3 to section 205(d) of the Federal Power Act, as amended, and preserve the sixty-day filing period, the Commission will amend its regulations so that initial rate schedules and changes in rate schedules shall be tendered not less than sixty (as provided by the statutory amendment) nor more than one hundred-twenty days prior to the date on which the schedule or the change in rates or conditions of service shall become effective. The change from ninety to one hundred-twenty days will simply preserve the sixty-day period within which filings may be made.

The amendment to paragraph (b) of § 35.3 changes the date on which rate schedules predicated on the construction of facilities may be filed. Such a rate schedule may now be filed one hundred-twenty days before it is to become effective. Previously the date was ninety days before the schedule was to become effective.

The amendment to paragraph (c) of § 35.2 extends the period in which the Director of the Office of Electric Power Regulation may notify a filing utility of any deficiencies in the filing. The period is extended from thirty to sixty days.

The Commission hereby adopts and makes effective these amendments without prior notice and opportunity of comment and without publication thirty days before their effective date. The amendment changing the filing date from no less than thirty to no less than sixty days prior to the date a rate schedule change is to become effective is required by statute (section

207(a) of (PURPA), is procedural in nature, and became effective along with the other provisions of PURPA on November 9, 1978. The other amendments merely conform related provisions of the regulations to the change mandated by PURPA and are procedural in nature as well. Section 553 of the Administrative Procedure Act (5 U.S.C. 553) does not require prior notice and opportunity to comment or publication thirty days before the effective date for procedural rules.

(Federal Power Act, as amended (16 U.S.C. 284(d)); Public Utility Regulatory Policies Act of 1978, Pub. L. 95-617; ; Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267)

In consideration of the foregoing the Commission hereby amends Part 35, Chapter I of Title 18, Code of Federal Regulations, as set forth below, effective immediately.

By the Commission.

Lois D. Cashell,
Acting Secretary.

[¶ 30,040]

44 F. R. 16895 (March 20, 1979).

FINAL REGULATIONS AMENDING AND CLARIFYING REGULATIONS UNDER THE NATURAL GAS POLICY ACT AND THE NATURAL GAS ACT

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rules.

SUMMARY: The Commission is amending its regulations relating to the effect of the Natural Gas Policy Act of 1978 on price escalator clauses in existing interstate and intrastate contracts for the first sale of natural gas and is also amending its protest procedures for filings under § 154.94 (h) and (i).

EFFECTIVE DATE: March 13, 1979.

FOR FURTHER INFORMATION:

Kenneth F. Plumb, Secretary, Federal Energy Regulatory Commission, 825 North Capitol St., N.E., Washington, D.C. 20426, (202) 275-4166.

SUPPLEMENTARY INFORMATION:

I. Introduction

March 13, 1979.

The Natural Gas Policy Act of 1978 [1] mandates a new legislative framework for the regulation of the natural gas industry. Its principal effect is to establish a comprehensive scheme of statutorily prescribed maximum ceiling prices applicable to discrete types of "first sales" of natural gas occurring in both interstate and intrastate commerce. As such, the Natural Gas Policy Act in many respects limits, replaces or supersedes the application of the previously controlling Federal statute, the Natural Gas Act,[2] and this Commission's authority and responsibility thereunder. Nevertheless, the Natural Gas Act continues to be of significance with respect to natural gas which was committed or dedicated to interstate commerce prior to enactment of the new legislative scheme.

Both the terms of the new statute and its legislative history demonstrate that the prices prescribed in Title I of the Natural Gas Policy Act are *ceiling* prices. Contractual provisions governing the purchase and sale of natural gas are superseded or nullified only to the extent that the contractual terms would provide for prices *in excess* of the statutory ceilings. Contractual terms which provide for prices below the statutory ceilings are unaffected.[3] In this regard, the Joint Explanatory Statement of the Committee on Conference (Conference Report) explains:

> [a]ll maximum lawful prices are ceiling prices only. In no case may a seller receive more than his contract permits.[4]

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[1] Pub. L. 95-621, 92 Stat. 3350.

[2] 15 U.S.C. § 717 *et seq.* (1938).

[3] Section 101(b)(9) of the Natural Gas Policy Act provides: [in] the case of any price which is established under any contract for the first sale of natural gas and which does not exceed the applicable maximum lawful price under this title * * *, such maximum lawful price * * * shall not supersede or nullify the effectiveness of the price established under such contract.

[4] H.R. Report No. 95-1752, 95th Cong., 2d Sess., at p. 74. See also, the statement of Congressman John D. Dingell at 95 Cong. Rec. 13117 (daily ed. October 14, 1978).

Generally speaking, the legislative scheme of the Natural Gas Policy Act presents little difficulty in the case of *new* sales contracts where the parties are free to agree to any price so long as it does not exceed the applicable statutory ceilings. Also, in the case of *existing* sales contracts which specify a fixed price or provide for a schedule of specific price increases, the respective rights and obligations of the parties to the contract are readily discernible and the relationship of the Natural Gas Policy Act to that contract are relatively straightforward.

The vast majority of existing sales contracts, however, are not of that character. Most contain escalator clauses of one kind or another which permit upward price adjustments during the term of the contract. These upward price adjustments do not provide for fixed or definite price increments and frequently are not tied to a specific schedule but are "triggered" by other means. The relationship of the Natural Gas Policy Act to these contracts is less straightforward.

Consequently, considerable uncertainty now exists with respect to the rights and obligations of the parties to existing sales contracts which contain escalator clauses. Moreover, a number of questions have arisen concerning the operation of certain escalator clauses within the framework of the Natural Gas Policy Act and, to the extent it remains applicable, the Natural Gas Act. The questions involve matters of considerable economic significance. Also the issues involved are directly related and are of consequence to the Commission's adminstrative and enforcement responsibilities under both the Natural Gas Policy Act and the Natural Gas Act. The Commission shall speak to these fundamental issues in this order.

II. Procedural History

The Commission's Interim Regulations Implementing the Natural Gas Policy Act at present contain the following admonition with respect to the operation of indefinite price escalator clauses:

> § 270.205 *Indefinite price escalator clauses.*
>
> (a) The establishment of maximum lawful prices under the NGPA shall not trigger indefinite price escalator clauses in existing intrastate or interstate contracts.
>
> (b) For purposes of this section, the term 'indefinite price escalator clause' shall have the same meaning as provided in section 105(b)(3)(B) of the NGPA.[5]

As noted in the Preamble to the Interim Regulations, § 270.205 was an attempt to incorporate the expression of Congressional intent at page 83 of the Joint Explanatory Statement of the Committee of Conference respecting the effect of the establishment of maximum lawful prices on indefinite price escalator clauses in existing intrastate contracts. The Commission's Interim Regulations applied the same rule to interstate contracts.[6]

Since the adoption of the Interim Regulations, we have received numerous comments and requests for clarification. The Commission first considered this matter at an open meeting on December 21, 1978. Memoranda discussing the issue were inserted into the public record in Docket No. RM79-3 in order to solicit an expression of views and comments and to assist the Commission in resolving the issues presented by the rule. These memoranda also sought to address several questions which had arisen at various NGPA implementation seminars, through the Commission's telephone hot-line program, and at public hearings held before staff panels in Washington, D.C., New Orleans, San Francisco and New York. In response to these comments, an oral argument was convened on the issues this order addresses before the Commission *en banc* on January 19, 1979. Nineteen parties participated in this argument,

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[5] Section 105(b)(3)(B) defines indefinite price escalator clause as follows:

(B) Definition of Indefinite Price Escalator Clause.—For purpose of this paragraph, the term 'indefinite price escalator clause' includes any provision of any contract—

(i) which provides for the establishment or adjustment of the price for natural gas delivered under such contract by reference to other prices for natural gas, for crude oil, or for refined petroleum products; or

(ii) which allows for the establishment or adjustment of the price of natural gas delivered under such contract by negotiation between the parties.

[6] See discussion at pages 19, *et seq.*, *infra.*

and numerous written comments were received.[7]

Following the oral argument, and after consideration of the comments, the Commission reached a tentative decision on the matters at issue in an open meeting on January 24, 1979.

The Commission had intended to issue an immediately effective final rule. The Commission was fully aware that continued uncertainty with respect to the contractual rights of the parties could (and would if allowed to go on much longer) have serious detrimental effects in the marketplace. It was our objective, therefore, to address this matter in a comprehensive way as early as practicable. However, upon concluding the review of the proposed order, the Commission recognized that there were still some lingering questions concerning the foundation and rationale advanced for the tentative conclusions. Also, in light of the complexities and importance of the issues involved, the Commission determined that it would be a more prudent course to test its preliminary conclusions in a further comment period and to seek to measure the consequences of the proposed decision.

For these reasons, on February 13, 1979, the Commission published its tentative conclusions in the form of a proposed rulemaking, vacating its previous determination to issue an immediately effective final rule. In its notice, the Commission not only asked for views on its proposed rule, but also invited comments on three alternative approaches.

On February 27, 1979, a public hearing was convened at which 20 parties appeared. In addition, we received written comments from numerous parties, including Members of Congress, government agencies and officials, producers, pipelines, distribution companies, other purchasers and consumer groups.

The Commission has evaluated each of the oral and written comments presented.[8] On the basis of that evaluation the Commission has determined to revise its preliminary views on these matters in a number of important respects. In the following section containing the Commission's Analysis and Decision we have dealt specifically with a number of the comments and have appended to this order a summary of the major arguments presented to us. It is entirely impracticable in the circumstances to discuss each and every argument submitted for our consideration. Accordingly, the Commission advises that, although we have considered the entirety of the comments submitted to us, some raise questions beyond the scope of this

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[7] *See*, Notice of Seminars Concerning Implementation of the Natural Gas Policy Act of 1978, November 14, 1978; *see also*, Order Setting Oral Argument, issued January 12, 1979, in Docket No. RM79-3. FERC News Release FE-474, November 13, 1978. FERC News Release FE-468, November 1, 1978.

[8] As we stated in our notice at page 5, the rule was proposed in a separate docket number. We reiterate that the action we take today, although issued in Docket No. RM79-22, reflects consideration of all relevant comments submitted in Docket Nos. RM79-3 and RM79-4. We further reiterate that we take official notice of and incorporate by reference the relevant portions of those dockets.

order and consequently are not dealt with herein.[9]

III. Commission Analysis and Decision

Before proceeding with our analysis, we believe it advisable to make a few preliminary points. First, the Commission fully accepts the view that the maximum lawful ceiling prices prescribed under the Natural Gas Policy Act are "just and reasonable" prices for purposes of section 4 and section 5 of the Natural Gas Act. The Congress has clearly said so in section 601 of the Natural Gas Policy Act. Moreover, the Commission does not (nor could it properly) object to such prices on the basis that they are "too high" or that they are not adequately "cost-related or justified". The Congress has struck the balance between consumer and producer interest; reserved to this Commission is only the task of administration and the authority to prescribe *higher* price ceilings in certain circumstances.[10]

Second, our purpose and responsibility here is to give effect to Congressional intent as that may be gleaned from the contemporaneous legislative history which was constructed at the time the Natural Gas Policy Act was enacted.

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[9] Tenneco Oil Company and others (Tenneco) have filed a motion requesting the Commission to waive the requirement that persons apply for rehearing of this order prior to seeking judicial review thereof. The need for rehearing of rules and regulations issued under the Natural Gas Policy Act arises under section 506 of that Act and Commission Order No. 21 (January 3, 1979). Section 506(b) does not expressly require rehearing of rules and regulations promulgated under the Natural Gas Policy Act. The Conference Report, however, "provides [that] judicial review [under the NGPA shall be] based on the Natural Gas Act * * *." H.R. Rep. No. 95-1752 at 122, 95th Cong., 2d Sess. (1978). In issuing Order No. 21, the Commission "determined to give effect to the expressed intention of [Congress] that generally the judicial review procedures under the NGPA should follow those under the Natural Gas Act" (Order No. 21 at 6), and adopted regulations providing for rehearing of rules and regulations issued pursuant to the Natural Gas Policy Act. Petitions for review of Order No. 21 are pending before the Fifth Circuit Court of Appeals in *Ecee, Inc., et al.* v. *FERC*, No. 79-1171.

Tenneco suggests that the rehearing requirement should be waived in this proceeding because there is no substantial need for further Commission action in this proceeding and because rehearing in this docket will adversely impact arrangements in the *Ecee* case to resolve expeditiously the question of the validity of Order No. 21. Tenneco presents various arguments in support of its position that rehearing should be waived in this proceeding. In essence, Tenneco argues that all interested persons have had several opportunities to present their views and that further delay would not be beneficial. While we sympathize with Tenneco's desire to obtain prompt judicial review of the Commission's order in this proceeding and agree that this proceeding must be brought to a conclusion as expeditiously as is practicable in the circumstances we must deny the request for waiver of the rehearing requirement.

In this proceeding, The Commission is acting pursuant to both the Natural Gas Policy Act and the Natural Gas Act, and is amending regulations adopted pursuant to the Natural Gas Act. Section 19(a) of the Natural Gas Act, 15 U.S.C. 717r(a) provides to all adversely affected persons a right to petition the Commission for rehearing of orders within 30 days after issuance. Thereafter, if rehearing is denied by the Commission, that person may seek judicial review as provided by section 19(b) 15 U.S.C. 717r(b). *See, e.g., Federal Power Commission* v. *Colorado Interstate Gas Co.*, 348 U.S. 492, 497-499 (1955). The Commission lacks the authority, to waive at the behest of any individual party the statutory right conferred on all interested persons to seek rehearing, just as no person may seek judicial review until he has exhausted that remedy. *E.g., Federal Power Commission* v. *Colorado Interstate Gas Co. supra; Boston Gas Co.* v. *Federal Energy Regulatory Commission*, 575 F. 2d 975, 977-979 (1st Cir. 1978). We also conclude that the same rule should apply under the Natural Gas Policy Act, both because Congress intended that judicial review under the Natural Gas Policy Act would generally follow the pattern of judicial review under the Natural Gas Act, and because exhaustion of rehearing remedies is a useful and practical administrative prerequisite to development of the Commission's final decisions. Furthermore, even if the Commission had the authority to waive the rehearing requirement under the Natural Gas Policy Act, we find no good cause for doing so in this proceeding. This order constitutes the Commission's initial promulgation of final regulations specifically addressing the operation of various indefinite pricing clauses. Rehearing will afford the Commission the opportunity to correct any errors prior to judicial review and to narrow and refine any issues which might be presented to the courts. Finally, rehearing will not unduly delay final resolution of the issues herein. For these reasons, Tenneco's motion is denied.

[10] *See*, sections 104(b)(2), 106(c), 107(b) and 109(b)(2).

Third, we cannot responsibly withdraw from the field and refuse to examine contractual arrangements as has been suggested to us. Both the Natural Gas Policy Act and the Natural Gas Act relate the terms of contractual arrangements between buyers and sellers to the controlling statutory requirement. On this last point, some further amplification may be helpful.

The Congress has resided in this Commission both the authority and responsibility to administer the Natural Gas Policy Act and, in particular, to insure the integrity of the ceiling prices established in Title I. In several instances statutory requirements are based on contractual relationships. In particular, with respect to natural gas not previously committed or dedicated to interstate commerce which is being sold under an existing contract, the statutory ceiling price is the price under the terms of the contract as it existed on November 9, 1978 (section 105(b)(1)). Also, the maximum lawful price which governs any rollover contract of natural gas which was not previously committed or dedicated to interstate commerce is governed by reference to the terms of the expired contract. Accordingly, under the legislative scheme, this Commission must necessarily become involved in reviewing the contractual arrangements between parties to existing contracts as they relate to natural gas not previously committed or dedicated to interstate commerce.

In the case of gas previously committed or dedicated to interstate commerce which is being sold under existing contracts, the Commission's responsibility is even more direct and substantial.[11] As previously noted in the introduction, the Natural Gas Act and the Commission's regulations continue to apply in many important respects to natural gas which was previously committed or dedicated to interstate commerce. It is true that the system of legislatively prescribed maximum ceiling prices replaces in large measure both the Commission's authority and its responsibility to establish just and reasonable rates applicable to producer sales in interstate commerce. And it is equally true that the Congress has deemed the statutory ceiling prices to be just and reasonable for purposes of sections 4 and 5 of the Natural Gas Act. But the question still remains whether there exists the requisite contractual authority to charge and collect such prices. The principal established in section 101(b)(9) of the Natural Gas Policy Act is that the legislation prescribes ceiling prices. The Congress specifically recognized that contract prices may be lower than the Federal maximum lawful price and that, in such circumstances, the contractual arrangement between the parties would continue to govern their relationdhip, and not be superseded by the Federal ceiling price.[12] Thus, where the Natural Gas Act continues to govern, the Congress seems to have intentionally preserved the *Mobile-Sierra* line of cases[13] which require this Commission to determine not only whether the rate is just and reasonable but also whether the sales contracts between the parties authorize those rates.

In the *Mobile-Sierra* cases, the Supreme Court held that a utility may not unilaterally file for increased rates when the company's contracts with its wholesale customers fix the rates for the contract term. This simply means that the contract between the parties governs the legality of the filing. Rate filings consistent with contactual agreements are valid; rate filings inconsistent with contractual obligations are invalid.[14] This rule of law parellels the preservation of a buyer's contractual right to purchase natural gas at prices below the Natural Gas Policy ceiling prices as contained in section 101(b)(9). Accordingly, the *Mobile-Sierra* doctrine requires the Commission to determine whether contractual authorization exists for the collection of the maximum lawful prices established by the Natural Gas Policy Act.[14]

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[11] The "more direct and substantial responsibility" to which the above paragraph refers attaches only to natural gas which *was* previously committed or dedicated to interstate commerce and which is being sold under an existing contract. The Commission takes this opportunity to emphasize the importance of the distinction between natural gas which was not committed or dedicated to interstate commerce on the day before date of enactment, and that which was. It is not a question of interstate or intrastate commerce, as such. In other words, natural gas which was not previously committed or dedicated to interstate commerce would not be subject to additional restrictions merely because the rollover contract was executed with an interstate pipeline or an interstate pipeline succeeded to the purchaser's interest in an existing contract. In either instance, sections 105 and 106(b) of the Natural Gas Policy Act would govern.

[12] Remarks of Congressman John D. Dingell, 95 Cong. Rec. 13117 (daily ed October 14, 1978).

[13] *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1950); *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1950); *United Gas Pipe Line Co. v. Memphis Light, Gas and Water Division, et al.*, 358 U.S. 103 (1958).

Because the statutory requirement and this Commission's responsibilities differ with respect to gas sold under existing contracts depending on whether the gas was previously committed or dedicated to interstate commerce, we will address these matters separately. For convenience, we will refer to "existing intrastate contracts" and "existing interstate contracts". Readers of the Commission's order should keep in mind that these terms do not accurately track the distinction which the Congress has drawn in the Natural Gas Policy Act.[15]

A. BACKGROUND

Existing intrastate contracts contain a variety of indefinite escalator and price redetermination provisions. One common form is a favored nations clause, requiring the price paid to increase to keep pace with other prices paid or natural gas in some defined area. Another is a price-reference clause which provides for an increase in price tied to any increase in the delivered price of some other fuel. Redetermination provisions generally provide that as a particular time during the contract term or upon the happening of a stated event, the parties will negotiate a new price. Still another common type of clause is the use in an intrastate contract of an "FPC clause", which would operate to increase the contract price whenever the FPC or FERC set a new just and reasonable rate.

Each of the aforementioned escalator and price redetermination provisions would appear to be "indefinite price escalator clauses" falling within the definition contained in section 105(b)(3)(B) of the Natural Gas Policy Act. Section 105(b)(3) applies to the post-1984 period and it may be suggested that the definition contained in clause (B) has no current applicability. However, the Conference Report discussion, appearing at page 83, indicates that the Conferees specifically considered the question of the pre-1985 applicability of indefinite price escalator clauses and had some specific views and instructions to offer with respect to their effect and applicability. It may be safely presumed, we think, that the Conferees intended to attach the same meaning to the term "indefinite price escalator clause" in its discussion as it attaches to the use of that term in the section of the Act to which that discussion, in large measure, pertains. On pages 82-83 of the Conference Report we are told several important things in this regard.

First, in the case of sales of natural gas under an existing intrastate contract, the statutory ceiling price depends upon the contract price in effect on the date of enactment of this Act (November 9, 1978). If the contract price in effect on November 9, 1978, is less than the new gas ceiling price (i.e., the section 102 price applicable to "new gas"), the maximum lawful price, beginning in December 1978 and any subsequent month, is the lower of (1) the price under the terms of the existing contract in effect on November 9, 1978, or (2) the new gas price. This is the formula provided in section 105(b)(1). Thus, we are told, "the price under the contract may escalate through the operation of both fixed price escalator clauses and indefinite price escalator clauses in existence as of the date of enactment, but the price may not exceed the new gas price."[16]

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[14] *Richmond Power & Light* v. *FPC*, 481 F.2d 490 (1973). *See Otter Tail Power* v. *FPC*, 536 F.2d 240 (1976); *Appalachian Power Co.* v. *FPC*, 529 F.2d 342 (1976).

[15] As noted previously in footnote 12, the distinction turns on whether the gas under the existing contract was previously committed or dedicated to interstate commerce on November 8, 1978.

[16] H.R. Report No. 95-1752, 95th Cong., 2d sess., at p. 82.

On the other hand, if the contract price in effect on November 9, 1978, is greater than the new gas price, the maximum lawful price formula under section 105(b)(2) would allow further increases in the contract price only to allow for adjustments for inflation, unless or until the new gas price catches up to the adjusted contract price. Thereafter the price may increase to track the increase in the new natural gas price. Accordingly, the operation of both fixed price escalator clauses and indefinite price escalator clauses is limited to the rate of the inflation adjustment unless and until the new gas price catches up and thereafter exceeds the inflation adjusted contract price.

Having thus set out the basic method for determining the maximum lawful price applicable to existing intrastate contracts, the conferees then turn to a discussion of the operation of indefinite price escalator clauses. This discussion notes that the provisions of section 313 of the Natural Gas Policy Act specifically prohibit prices paid in any sale of high-cost natural gas, from triggering the operation of any indefinite price escalator clauses. The conferees also observe that the Federal government has ceded to states under section 602 the authority to further limit the operation of price escalator clauses as an adjunct to their authority to prescribe lower maximum lawful prices for the first sale of natural gas produced within the state.

Then the following paragraph appears:

> Some intrastate contracts currently in existence contain indefinite price escalator clauses which can be triggered by a number of factors, including adjustments by the Commission of "just and reasonable" rates established under the Natural Gas Act. The conferees do not intend that the mere establishment of the ceiling prices under this Act shall trigger indefinite price escalator clauses in existing intrastate contracts. Once natural gas is sold pursuant to the ceiling prices under this Act, such clauses would be activated as limited by this Section.

In the immediately preceding paragraph of the Conference Report, we are told that "[t]his section of the Conference Agreement is not intended to apply to interstate contracts in existence as of the date of enactment" [11], and that the Conferees were aware that "[s]uch contracts are currently subject to regulation by the Commission pursuant to the Natural Gas Act." The Conferees then go on to assert that "[C]ommission regulations bar the use of indefinite price escalator clauses in interstate sales."

These two paragraphs which appear at page 83 of the Conference Report, lie at the root of the debate and confusion which attends the question of the operation of indefinite price escalator clauses under the Natural Gas Policy Act. And it is this Commission's attempt to give expression to the Congressional intent embodied in these paragraphs that has focused comment on the important questions which relate to the operation of price escalator clauses under the Act.

In drafting its Interim Regulations implementing the Natural Gas Policy Act, the Commission merely attempted to incorporate in its Regulations an approximation of the legislative expression contained on page 83 of the Conference Report. Inasmuch as the Regulations were required to be effective on December 1, 1978, only three weeks from date of enactment, time did not permit a considered exposition of the effect of indefinite price escalator clauses under the Act. Thus, the Commission provided in § 270.205 (18 CFR 270.205) that:

> (a) The establishment of maximum lawful prices under the NGPA shall not trigger indefinite price escalator clauses in existing intrastate or interstate contracts.
>
> (b) For purposes of this section, the term "indefinite price escalator clause" shall have the same meaning as provided in section 105(b)(3)(B) of the NGPA.

With respect to existing intrastate contracts, § 270.205 approximates the language contained in the second sentence of the last paragraph on page 83 of the Conference Report. The section was made equally applicable to interstate contracts in order to make clear that the current bar to certain indefinite price escalator clauses under existing Commission Regulations would continue in effect. In so doing, we were attempting to give expression to the intent and requirement of the penultimate paragraph contained on page 83 of the Conference Report.[18]

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[11] Presumably the reference to "this section" is a reference to section 105 of the Natural Gas Policy Act.

Existing interstate contracts, like their counterparts in the intrastate market, contain a variety of price escalator clauses. But unlike the situation that obtains with respect to intrastate contracts, certain price escalator clauses contained in interstate contracts have been prohibited or made inoperative under Commission Regulations promulgated pursuant to the authorities contained in the Natural Gas Act.

The Current prohibitions are contained in § 154.93 of the Commission's regulations under the Natural Gas Act. Generally speaking, this Regulation makes inoperative any provision in an interstate contract which provides for a change in price which is not in the form specifically permitted by the regulations. Specifically, § 154.93 provides in pertinent part:

> *Provided*, That in contracts executed on or after April 3, 1961, for the sale or transportation of natural gas subject to the jurisdiction of the Commission, any provision for a change of price other than the following provisions shall be inoperative and of no effect at law; the permissible provisions for a change in price are:
>
> (a) Provisions that change a price in order to reimburse the seller for all or any part of the changes in production, severance, or gathering taxes levied upon the seller;
>
> (b) Provisions that change a price to a specific amount at a definite date;
>
> (b-1) Provisions that permit a change in price to the applicable just and reasonable area ceiling rate which has been, or which may be, prescribed by the Commission for the quality of the gas involved; and
>
> (c) Provisions that, once in five-year contract periods during which there is no provision for a change in price to a specific amount (paragraph (b) of this section), change a price at a definite date by a price-redetermination based upon and not higher than a producer rate or producer rates which are subject to the jurisdiction of the Commission, are not in issue in suspension or certificate proceedings, and, are in the area of the price in question: *Provided further*, That any contract executed on or after April 2, 1962, containing price-changing provisions other than the permissible provisions set forth in the proviso next above shall be rejected. [Order 242, 27 FR 1357, Feb. 14, 1962, as amended by Order 329, 31 FR 15486, Dec. 8, 1966.]

Thus, current Regulations of the Commission declare "inoperative and of no effect at law" most indefinite price escalator clauses. And it was of this prohibition that Senator Jackson spoke when he stated that there was no "intent to change or otherwise modify that prohibition".[19] The problem occurs with respect to paragraph (b-1) of the above quoted proviso. There the Regulation specifically allows to operate a provision which would "permit a change in price to the applicable just and reasonable area ceiling rate which has been, or which may be, prescribed by the Commission for the quality of the gas involved". Contractual clauses of the character permitted under paragraph (b-1) of § 154.93 have come to be known as "area rate clauses" or "FPC clauses".

First, it should be noted that an "area rate clause" would fall within the technical definition of indefinite price escalator clauses contained in section 105(b)(3)(B) of the Natural Gas Policy Act. Further evidence that the Congress regarded area rate clauses as indefinite price escalator clauses can be gleaned from the first sentence in the last paragraph appearing on page 83 of the Conference Report which states, "[s]ome intrastate contracts currently in existence contain indefinite price escalator clauses which can be triggered by a number of factors, *including* adjustments by the Commission of just and reasonable rates established under the Natural Gas Act". It is possible to structure an argument that the Congress misperceived the effect of the Commission's Regulations believing that those Regulations constrained the operation of area rate clauses in interstate contracts, thus making it unnecessary for the Congress to address the question in specific terms. We do not think, however, there is much substance to such an argument. The more likely construction of legislative intent is that the Congress intended that the Commission continue to prohibit that which was prohibited, but allow to operate that which has been permitted under the terms of the Commission's Regulations.

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[18] In this regard Senator Henry M. Jackson, Senate Floor manager for consideration of the Natural Gas Policy Act, stated, in referring to indefinite pricing provisions, "However, operation of those clauses is prohibited by current Commission Regulations. There is no intent to change or otherwise modify that prohibition." 95 Cong. Rec. S. 15021 (daily ed. Sept. 13, 1978).

[19] 95 Cong. Rec. S. 15021 (daily ed. Sep. 13, 1978).

It is from this perspective, that the Commission examined in its proposed rulemaking the provisions of § 154.93 of its regulations under the Natural Gas Act. After reviewing the historical development of the prohibitions contained in § 154.93 and the development of area rate clauses, the Commission reached the tentative conclusion that any contractual clause which tracked the literal text of paragraph (b-1) of § 154.93 would not be triggered by the Natural Gas Policy Act. And, any price escalator clause which did not follow the literal text of paragraph (b-1) of § 154.93, was by the specific terms of that Regulation made "inoperative and of no effect at law". Accordingly, the Commission reasoned that any such clause would be given no greater effect than a clause specifically permitted under paragraph (b-1). With respect to whether a conforming area rate clause was triggered, the Commission noted that the Regulation permitted price increases only to the "applicable just and reasonable area rate * * * *prescribed by the Commission.*" The Natural Gas Policy Act ceiling prices are not prescribed by the Commission; they are prescribed by Congress. Accordingly, adopting what it characterized as a "plain meaning" construction, the Commission stated that area rate clauses conforming to the literal text of the Commission's regulations would not trigger to the Natural Gas Policy Act rates and those which did not conform to the literal text were rendered inoperative under the regulation.

Similarly, it was the Commission's preliminary view that intrastate contracts which contained an "FPC-type clause" conforming to the literal text of the Commission's Regulations would also not trigger the Natural Gas Policy Act rates. Moreover, the Commission expressed the opinion that area rate clauses, whether in interstate or intrastate contracts, which permitted escalation in the event of action to be taken by a "successor governmental authority" should not be read as triggered by the Natural Gas Policy Act rates. Here the Commission reasoned that Congress was not a "successor" to the Commission but rather is the Commission's predecessor and progenitor from which its authority derives.[20]

The Commission is now convinced that the initial view taken in the proposed rulemaking was incorrect in a number of respects and must be revised.

The principal flaw in the Commission's reasoning lies in the too narrow focus of the proposed rule on the provisions of § 154.93 (b-1) and the weight given to the literal text of that provision. Several persons commenting in this proceeding pointed out the weakness in this approach with convincing argument.[21]

As the Commission noted in its proposed rulemaking, the current prohibitions embodied in § 154.93 find their antecedents in Federal Power Commission Order No. 232 which was issued in 1961. That order prospectively banned the effectiveness of certain types of indefinite pricing clauses in interstate contracts. The FPC was primarily concerned with favored nation, redetermination, or spiral escalation clauses which it characterized as "undesirable, unnecessary and incompatible with the public interest." In essence the Commission determined that such indefinite escalator provisions were "contrary to the public interest" and must be prohibited.[22] It is also worth noting that the FPC had initially proposed an outright bar on all indefinite pricing provisions, only permitting producers and pipelines to include definite pricing provisions in contracts.

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[20] The Commission also reached the tentative conclusion that parties to interstate contracts were generally free to amend their contracts to allow for the payment of the statutory ceiling. The proposed order also addressed the question of amendment authority with respect to interstate contracts.

[21] *See,* comments of the Public Service Commission of the State of New York filed February 26, 1979, in Docket No. RM79-22 and comments of Indicated Producers filed February 26, 1979, in Docket No. RM79-22.

[22] Order No. 232-A, 25 FPC 609 (1961).

On rehearing, the FPC amended its proposed ban to allow certain:

"Limited price-redetermination provisions, invokable not more than once in every five-year contract period and based upon rates subject to this Commission's jurisdiction (*and, therefore, controlled*)." [23] These limited price-redetermination provisions were allowed in order to permit pricing flexibility and to provide an incentive for long-term contracts. Several conclusions of importance to the instant proceeding can be drawn from this brief recounting of the development of § 154.93 of the Commission's Regulations. First, the rule firmly stands on a determination that prohibited indefinite escalation provisions are "contrary to the public interest". The continued viability and application of this rule, therefore, would seem to turn on whether the Commission could successfully establish that it had a reasonable basis for concluding that a particular prohibited clause was contrary to the public interest.

It is now the Commission's view that we would lack authority to apply § 154.93 to make inoperative and of no effect at law a price escalation provision as would have specifically bound the parties to the outcome of legislative or specific Congressional action. Thus, if a contract provided for escalation to rates established by the Congress, or by legislative action, or specifically referenced the Natural Gas Policy Act prices, this Commission would be without authority to apply § 154.93 to preclude the operation of such clauses on a "contrary to the public interest" standard. We would agree that if the Commission found it appropriate to allow parties to bind themselves to the outcome of Commission proceedings in the exercise of Congressionally derived authority, we could not rationally maintain that it was contrary to the public interest for the parties to contractually bind themselves to actions taken by the Congress directly.

Moreover, we do not believe that we could apply § 154.93 on a "contrary to the public interest" standard so as to preclude an interpretation of the contractual arrangement between the parties or an amendment to such contract which would bind the parties to the Natural Gas Policy Act maximum lawful ceiling prices. Thus, we have concluded that the Commission's original focus on the provisions of § 154.93 was misplaced. And, to the extent that section of the Commission's regulations under the Natural Gas Act remains applicable, it is our view that it neither bars nor makes ineffective specific contractual provisions which incorporate the Natural Gas Policy Act prices or provisions which provide for price escalation tied to the outcome of Congressional or legislative action.

Those indefinite price escalation clauses which § 154.93 specifically intended to prohibit, such as favored nation, redetermination, or spiral escalation clauses, would continue to be rendered inoperative under the regulation. This result was clearly the intent of the Congress at the time the Natural Gas Policy Act was enacted.

The question still remains, however, whether "typical area rate clauses" operate to permit escalation of contract prices to the maximum ceiling prices provided in the Natural Gas Policy Act. The answer to this question, the Commission believes, is necessarily linked to questions of contractual interpretation and the intent of the parties to that contract. Before turning to that subject, it may be useful to first return to the legislative history of the Natural Gas Policy Act to search for Congressional guidance and instruction on this subject.

B. CONGRESSIONAL INTENT RESPECTING THE OPERATION OF AREA RATE CLAUSES

The question of Congressional intent as it relates to the operation of area rate clauses was extensively discussed in the written comments and in oral argument before the Commission. A perusal of the contemporaneous legislative history constructed at the time the Natural Gas Policy Act was considered, however, reveals little in the way of direct and specific guidance on this matter. As previously discussed, there appears only the discussion on pages 82 and 83 of the Conference Report and the statement by Senator Jackson during the time of Senate floor consideration. In large measure, therefore, the Commission is left to deduce the intent of Congress with regard to this matter.

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[23] FPC Order No. 232-A, (Emphasis supplied).

Several members of the House and the Senate together with Secretary Schlesinger have filed comments with the Commission. Senator Domenici of New Mexico and Congressman Treen of Louisiana also appeared and offered their views in oral argument before the Commission.[24] It is true, as the New York Public Service Commission [25] points out, that the Commission must look to the *contemporaneous* legislative history. In other words, we must look to see what Congress said at the time the Act was considered. On the other hand, while we cannot regard the views stated by the members of the Congress and Secretary Schlesinger as constituting official legislative history, it is entirely appropriate to evaluate those views as they may provide guidance to the Commission in its effort to deduce legislative intent. Similarly, the Commission has evaluated the views of the other parties in construing Congressional intent.

The arguments concerning legislative intent proceed on two basic lines. First are those which emphasize the basic objectives of the Natural Gas Policy Act as being grounded in the need to (1) remove distinctions between inter- and intrastate markets, (2) provide price predictability, and (3) establish incentives for increased production. This line of argument places heavy emphasis on Congressional recognition that the real dollar value for flowing gas should be preserved through the mechanism of statutory automatic inflation adjustments to the maximum ceiling prices. Considerable weight is also given to the Congress having deemed the maximum lawful ceiling prices to be "just and reasonable" for purposes of section 4 and 5 of the Natural Gas Act. Several commenters have also called the Commission's attention to the fact that the section 103 price ceiling (relating to new, onshore production wells) and the section 102 price (relating to new gas production) as well as the section 107(a)(1) price (relating to deep wells) all employ concepts which measure eligibility on the basis of drilling activity which occurred on or after February 19, 1977—activity which in the extreme would have occurred almost 19 months *prior* to date of enactment. It is argued that the use of the February 19, 1977 date evidences a specific Congressional intent to provide a statutory substitute for the so-called "missing biennium rate".[26] Lastly, this line of argument calls attention to the various economic analyses which were prepared and are a part of the contemporaneous legislative history of the Natural Gas Policy Act. Each of these analyses makes assumptions with respect to producer revenues, and consumer impacts and supply response which are generally consistent with an expectation that the area rate clauses in existing contracts would trigger to the statutory ceiling prices.[27]

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[24] *See*, Comments of Senator Pete Domenici filed January 18, 1979 in Docket No. RM79-3; *see also*, Statement of Senator Pete Domenici filed February 27, 1979 in Docket No. RM79-22, and oral argument February 27, 1979, Tr. 3-10; and Statement of Congressman David Treen at oral argument February 27, 1979, Tr. 21-24.

[25] Comments of the Public Service Commission of the State of New York, *supra*, at 3, 4.

[26] In Opinion 770-A the Federal Power Commission had committed to a biennium rate process which would adjust the national rate every two years. The Commission had initiated a proceeding to establish a biennium rate for 1977 and 1978 gas vintages, but suspended that proceeding after both Houses of Congress passed legislation which would discard the Natural Gas Act cost-based pricing methodology. *See*, Comments of the State of Texas, filed February 27, 1979 and Statement of the Texas Independent Producers and Royalty Owners Association, filed February 27, 1979.

The second line of argument emphasizes that the Natural Gas Policy Act establishes a series of *ceiling* prices. And that contracts which provide for lower prices are intended to be given contract sanctity and left undisturbed by the passage of the Natural Gas Policy Act. This line of argument places heavy weight on the Congressional intent to provide a transition to deregulation by 1985. Thus, Congress provided for scheduled increases in the maximum lawful ceiling prices with the full expectation that market forces would develop as supply and demand are gradually brought into balance—thus justifying the removal of price controls at the end of the six-year period. Accordingly, this line of argument would suggest that it is basically inconsistent with the transitional mechanisms for deregulation to conclude that the vast majority of existing contracts which contain area rate clauses all trigger to the maximum ceiling prices provided in the Natural Gas Policy Act, thereby locking the purchaser into the obligation to pay the maximum ceiling prices to the preclusion of his ability to bargain for a lesser price.

Also, although no party to this proceeding appears to have raised the point, it may be contended that the blanket triggering of area rate clauses to the Natural Gas Policy Act ceiling prices would seem to run counter to the Congressional objectives in Title II of the Natural Gas Policy Act concerning incremental pricing. At least one of those objectives is to pass a portion of the incremental cost of purchased natural gas directly on to price sensitive industrial boiler fuel users to bring their cost in line with alternative fuel cost so as to hasten the time at which supply and demand comes into balance, and to create incentives for pipelines to negotiate prices to guard against loss of their industrial load. It would seem basically inconsistent to maintain that interstate pipelines are *both* forced to pass these incremental costs on to their most price sensitive marginal customers and at the same time, bound under their previously existing contractual arrangements to pay the maximum ceiling prices to the preclusion of their ability to negotiate lesser prices.

The Commission does not believe in the instant case that an entirely satisfactory resolution of the multiple objectives of the Natural Gas Policy Act can be found. As these objectives relate to the matter at hand they appear to be in basic conflict. If area rate clauses are triggered to the Natural Gas Policy Act ceiling prices, some Congressional objectives will be furthered while others would appear to be frustrated. On the other hand, if area rate clauses are not triggered, some Congressional objectives will be met while others would be frustrated. Also, our search for a middle ground has not borne much fruit. We are able, however, to draw some conclusions with respect to the intended operation of the Commission's current prohibitions on indefinite price escalator clauses contained in § 154.93 of its regulations under the Natural Gas Act.

After evaluating the comments and views expressed, it would appear that, while the Congress cannot be said to have conclusively *intended* to have area rate clauses trigger to the Natural Gas Policy Act ceiling prices to the preclusion of the parties ability to negotiate lesser prices, the Commission cannot find a convincing basis upon which to conclude that the Congress *did not intend* to allow area rate clauses to trigger to the statutory ceiling prices.

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[27] The studies were prepared by the Department of Energy/Energy Information Administration, the staff of the House Subcommittee on Energy and Power and the Congressional Budget Office. The Commission believes it appropriate to comment very briefly on this point. Several factors reduce the persuasiveness of the argument. First, not one of the studies makes a specific assumption concerning the applicability of area rate clauses. It could equally well have been assumed that the relative supply/demand imbalance in the marketplace was sufficient to drive the current prices to the maximum statutory ceilings. Second, the studies do not appear to take into account that a considerable amount of gas continues to be sold at fixed price contracts. Third, as Secretary Schlesinger pointed out in his statement, the DOE/EIA study assumes that existing stripper well prices would not rise to the stripper ceiling "until current contracts expired". While no explanation of this assumption is given, it would seem inconsistent with the theory that all area rate clauses are triggered to the Natural Gas Policy Act ceilings and at the same time assume that in the case of existing stripper wells the price ceilings would not be obtained until current contracts expire.

In short, we find that the prohibitory language in § 154.93 of the Commission's regulations to be too slender a reed upon which to place the weight of a Commission decision that area rate clauses were intended not to be triggered by the statutory ceiling prices. The Congressional direction contained on page 83 of the Conference Report is simply too ambiguous to rely on to reach a conclusion of this consequence.

It does appear that under paragraph (b-1) of § 154.93, the Federal Power Commission permitted, as consistent with the public interest, price escalator clauses to operate to bind the parties to the outcome of Commission proceedings which prescribed just and reasonable rates of general applicability. The FPC appeared to require as a matter of public policy only that the rates be controlled,[28] that they be just and reasonable, that they be generally applicable to an area, and that they apply to the quality of the gas involved (i.e., vintage). The Natural Gas Policy Act maximum ceiling prices fit each of these criteria.

It is true that the rates are not prescribed by the Commission but by the Congress. While that distinction may have some importance to the parties to a contract and parties in interest to interstate sales contracts,[29] it cannot serve as a proper basis for the Commission concluding that its regulations under § 154.93 preclude the parties from relying on area rate clauses as a basis for charging and collecting the Natural Gas Policy Act statutory prices. To our earlier discussion concerning the applicability of § 154.93 of our current regulations, we would add only the question: Does it seem reasonable that the Congressional reliance on the prohibitions contained in existing Commission regulations—which *permitted* and did not prohibit area rate clauses—could be construed as an intention to disallow the operation of area rate clauses? We think not.

Accordingly, the Commission has concluded that § 154.93 of its current regulations does not *bar* or proscribe reliance on an appropriate area rate type clause as authority for charging and collecting applicable Natural Gas Policy Act prices. It could be expected that Congress would have little patience with the assertion by this Commission, on a public interest standard, that § 154.93 bars the operation of area rate clauses to preclude the incorporation of rates which the Congress has determined are "just and reasonable" simply on the basis that such rates were prescribed by the Congress and not by this Commission. It is even harder to conclude that Congress *intended* that reading of § 154.93.

The Commission's inquiry does not end with the above conclusion, however; nor does its responsibility. Although we have concluded that our existing regulations do not preclude reliance on area rate clauses, the question still remains whether such clauses, in fact, operate to trigger to the Natural Gas Policy Act ceiling prices. As previously noted, the answer to this question turns on matters of contract construction and the intent of the parties.

C. OPERATION OF AREA RATE CLAUSES—CONTRACTUAL CONSTRUCTION AND INTERPRETATION

A great number of the comments filed directed their attention to the intent of parties who entered into area rate clauses. Of particular relevance was the substantial level of agreement between most sellers and buyers as to what was generally intended when the area rate clause was executed. Equally important, however, was the representation that area rate clauses vary considerably in their wording, and that no definitive statement could therefore be made by the Commission that would resolve all concerns.

Most sellers of natural gas in the interstate market have taken the view that the intent of parties in agreeing to an area rate clause was to permit escalation to the highest ceiling price permitted by law.[30] Most interstate pipeline purchasers have endorsed this position. At oral argument on February 27, 1979, the Interstate Natural Gas Association of America (INGAA), a trade association of interstate pipelines, stated that it was the intent of purchasers in agreeing to area rate clauses to permit escalation to "the level of the generally applicable ceiling rate which has been established by *Federal authorities,*" (emphasis added) rather than by the Commission.[31] Individual pipelines have expressed the same view.[32]

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[28] See page 26, *supra*.

[29] See following discussion on pages 39-41, *infra*.

Other pipelines have commented that it was their intent in acceding to the inclusion of an area rate clause in their own purchase contracts to permit escalation to the highest ceiling price of general applicability, whether set by the FPC or any other authority,[33] or to the highest ceiling permitted by law.[34]

A contrary interpretation was suggested by another pipeline company, however. Consolidated Gas Supply Corporation would interpret a clause which calls for escalation to a price prescribed by the Commission "or *successor* governmental authority" as *not* permitting escalation to NGPA prices. Its rationale is that by using such a clause the parties "clearly contemplated the fixing of rates through agency-type hearings".[35] Consolidated would, however, permit the operation of clauses worded to permit escalation to rates set by *other* governmental authority rather than the Commission or "*successor* governmental authority". The representative for Panhandle Eastern Pipeline Company went a step further, suggesting in oral argument on January 19, 1979, that interpretation of the area rate clause isn't just a question of what the language says. It is also a question of what was in the minds of the parties when they entered into it * * *." [36]

The State of Michigan and the Michigan Public Utilities Commission stated yet another position on the intent of contracting parties:

> Michigan wishes to stress that the interpretation of natural gas contracts must rest strictly on the language chosen by the parties for these agreements are not merely private bilateral contracts but are tariffs as well.

Michigan then goes on to say that the intent of parties, obvious under the plain meaning of the clause, is not to permit escalation to the NGPA rates.[37]

It is apparent from the comments received in this proceeding, that the wording of area rate and similar clauses varies widely, and interpretations may differ. The wording of a particular clause and the affect ascribed to that clause by the contracting parties will generally be determinative of whether a particular area rate clause authorizes the collection of the Natural Gas Policy Act prices.

Nevertheless, in light of our administrative responsibilities under the Natural Gas Policy Act and the Natural Gas Act with respect to contractural matters, we believe it both necessary and appropriate to state some general views. At the outset, however, we wish to make it perfectly clear that we do not intend to establish a *dispositive* view of this matter. Several parties have cautioned us against that approach.[38] It is asserted that the record in this proceeding will simply not support a conclusive ruling on the operaton of area rate clauses. We would agree. Accordingly, our views on this matter should be taken in the nature of "guidance".

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[30] *See, e.g.,* Statement of Mobil Oil Corporation, filed February 27, 1979, at 1, 2. Comments of Indicated Producers, filed February 27, 1979; Comments of Shell Oil Company filed February 22, 1979; and Statement of Independent Petroleum Association of America filed February 27, 1979.

[31] Oral argument, January 19, 1979, in Docket No. RM79-23, Tr. 16, *See also,* Tr. 20; and INGAA's Comments filed February 27, 1979, at 2.

[32] *See, e.g.,* Comments of Michigan-Wisconsin Pipe Line Company filed January 18, 1979, in Docket No. RM79-3 at 1.

[33] *See, e.g.,* Comments of Natural Gas Pipeline Company of America, filed January 18, 1979, in Docket No. RM79-3, at 3.

[34] Comments of Texas Gas Transmission Company, filed February 27, 1979, at 3.

[35] Supplemental Comments of Consolidated Gas Supply Corporation filed January 31, 1979, in Docket No. RM79-3, at 1; *see also,* oral argument January 19, 1979, Tr. 132.

[36] Oral argument, January 19, 1979, in Docket No. RM79-3, Tr. 100.

[37] Oral argument, February 27, 1979, in Docket No. RM79-22, Tr. 226.

[38] *See in particular,* Comments of "Eight Independent Producers", filed February 27, 1979; Chevron U.S.A., filed February 26, 1979; and, Statement of Jack D. Head on Behalf of Texas Eastern Transmission Corporation and Transwestern Pipeline Company, filed February 27, 1979.

The Commission recognizes that the parties to existing interstate sales contracts are not the only parties in interest. As has been forcefully and correctly pointed out in these proceedings,[39] the gas consumer and the local distribution companies served by those pipelines have very direct and substantial interest in these matters. Nevertheless, as the courts have recognized in questions of contract interpretation, great weight must be given to the intent of the parties to the contract.[40]

After the fullest consideration of the comments received in this proceeding, it is clear that many parties to interstate sales contracts which contain area rate clauses were of the view that, by agreeing to an area rate clause, the parties intended to permit prices to escalate to the highest generally applicable ceiling rate allowed by governmental authority provided the rate was "just and reasonable" and the gas under the contract qualified for that rate. As stated by Michigan Wisconsin Pipe Line Company in its written comments:

> * * * [P]arties to interastate contracts generally believed that some form of governmental action would occur. The purpose of the area rate or FPC clauses was simply to permit the producer who committed his gas to the interstate market prior to such action occurring to benefit from such action provided that by governmental decision, he was otherwise permitted to do so. In short, parties agreed to make pricing a matter of governmental decision under circumstances where government chose to act.[41]

The Commission is unable to conclude that this is an *unreasonable* interpretation of the intent of the parties to area rate clauses. Nor can we find a compelling public policy basis for precluding this interpretation. We would hold this view even if the area rate clause merely tracked the literal text of § 154.93(b)-(1). To the extent that such clauses reference action to be taken by other governmental authority the persuasiveness of this argument is strengthened. As noted earlier, we cannot find specific Congressional direction that we do so. And we find little basis for our imposing on the parties to the contract an interpretation which is contrary to the intent that they ascribe to their agreement simply on the ground that the rates were prescribed by the Congress and not by the Commission, or on the basis that the increased rate levels were not evolved through a cost-based rate methodology or were not adequately cost justified.[42] Inasmuch as the Congress has determined to abandon cost-based methodologies in favor of statutory ceiling prices, we find it difficult to conclude that the Congress nonetheless intends this Commission in the exercise of its continuing authority under the Natural Gas Act to act, on its own motion, to prevent reliance on area rate clauses as contractual authority for the Natural Gas Policy Act ceiling prices in circumstances where both parties to the contract interpret their bargain to permit price escalation to those statutory ceiling prices.

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[39] *See,* oral presentation of New York Public Service Commission in oral argument before the Commission on February 27, 1979.

[40] *See, Louisiana-Nevada Transit Co.* v. *Woods,* 383 F. Supp. 177 (1975).

[41] Comments of Michigan Wisconsin Pipe Line Company filed January 18, 1979, in Docket No. RM79-3 at 1.

[42] Another point should be made at this juncture. In the Notice of Proposed Rulemaking, the Commission stated that it did not *believe* that a reference to a "successor authority" could be interpreted to include the Congress. We now reverse that position. We find convincing the arguments that the Congress, in the exercise of direct ratemaking authority, has replaced and, in that sense, succeeded to the Commission's exercise of responsibility in this matter. On the other hand, we take cognizance that one party to a contract which contains an area rate clause, Consolidated Gas Supply Corporation, would interpret a clause which calls for price escalation to levels prescribed by the Commission "or successor Governmental authority" as not permitting escalation to the Natural Gas Policy Act prices. Consolidated's view is that it had contractually bound itself only to the outcome of agency-type hearings in which administrative protections not available in the legislative process were present. These would presumably include the opportunity to protest in an administrative proceeding, to require agency findings, and to obtain judicial review. Consolidated should not be precluded from pursuing that view of the matter. And the Commission intends no such result. We are simply withdrawing from the assertion that under a "plan meaning" construction of the contract the Congress could not be considered a "successor".

Accordingly, in the first instance and as a general matter,[43] the Commission will give effect to the intention of the parties and permit reliance on area rate clauses for the requisite contractual authority in interstate sales contract to permit escalation to the Natural Gas Policy Act ceiling prices. This appears particularly appropriate in the case of the ceiling prices established under sections 104 and 106(a) of the Natural Gas Policy Act. While these prices are not specifically prescribed by the Commission in the same way area or nationwide rates were, the section 104 prices are based and inextricably linked to previously prescribed FPC rates. What the Congress did in enacting section 104 was to freeze as of April 20, 1977 the presently lawful FPC rates and to change the escalation factors from those established by the FPC to a different method required by the Congress.[44]

As explained by Congressman Dingell on behalf of the House floor managers at the time the Natural Gas Policy Act was considered, the section 104 rates "incorporate by reference" the Commission-prescribed rates.[45] As Panhandle Eastern Pipeline Company and Trunkline Gas Company put the matter in their joint written comments, "the section 104 rates are the historical, regulatory and contractual progeny of the just and reasonable rates resulting from the area rate proceedings under the Natural Gas Act".

As noted earlier the Commission does not intend to have its comments respecting the operation of area rate clauses be viewed as an attempt to speak in a dispositive way to this subject. Rather our intent is merely to express an *administrative* view of this matter to provide quidance to the parties in interest as to how the Commission intends to discharge its responsibilities under the Natural Gas Policy Act and the Natural Gas Act. As the comments and these proceedings make abundantly clear, some parties ascribe a different interpretation to the operation of area rate clauses and it is the Commission's view that we must provide a forum to permit protest to be made to the utilization of area rate clauses as contractual authorization for the Natural Gas Policy Act prices.

D. DECISION

On the basis of the foregoing analysis, the Commission arrives at the following decisions:

1. Existing Interstate Sales Contracts.

To the extent that the Natural Gas Act remains applicable to an existing interstate contract, the provisions of § 154.93 of the Commission's regulations, which have been promulgated under that Act, do not preclude the operation of price escalation provisions in a contract, the terms of which specifically permit escalation to Congressionally or legislatively authorized prices or which specifically reference Natural Gas Policy Act prices. Also, the Commission will, in the absence of specific contractual language to the contrary, generally interpose no objection to the parties to an interstate contract ascribing an interpretation to an area rate clause in its contract as would authorize escalation to, and collection of, the Natural Gas Policy Act price ceilings.

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[45] 95 Cong. Rec. H 13117 (daily ed. October 14, 1978). Statement of Congressman John D. Dingell.

[43] Ratemaking is a legislative function exercised under the interstate commerce clause of the United States Constitution. Art. I, § 8, clause 3. *Prentis* v. *Atlantic Coast Line Co.*, 211 U.S. 210, 226 (1908). *See also. Munn* v. *Illinois*, 94 U.S. 113, 133-34 (1877); *Ohio Valley Co.* v. *Ben Avon Borough*, 253 U.S. 287, 289 (1920); 253 U.S. 287, 289 (1920); *Morgan* v. *U.S.*, 279 U.S. 468, 279 (1936) *Colorado Interstate Gas Co.* v. *FPC*, 324 U.S. 581, 589 (1945). The Commission has exercised this function, by delegation from the Congress in the Natural Gas Act, with respect to producer sales since 1954. *Phillips Petroleum Co.* v. *Wisconsin*, 347 U.S. 672 (1954). By enacting the NGPA with the exception of the provisions in sections 104(b)(2), 106(c), 107(b) and 109(b)(2), which give the Commission the authority to set rates in excess of the NGPA ceiling prices, the Congress has rescinded that much of its rate-setting authority as it had delegated to the Commission under the Natural Gas Act. And the Congressional action provides legislatively set rates for the same period that would have been the subject of the latest Commission biennial review, thus obviating the necessity for this Commission to conclude or take further action with respect to that proceeding.

[44] The same is generally true of the section 106 price ceilings applicable to rollovers of interstate contracts, although here the Congress also added a specific formula which approximates previous FPC prescribed rates.

In the event that interstate pipeline purchasers contest the use or reliance by sellers on area rate clauses in their contracts, the Commission will provide an opportunity to protest. Once a protest to contractual authorization is submitted, the Commission will then consider the matter and attempt to state its view. Other parties in interest, including state commissions, local distribution companies and other aggrieved parties will be permitted to participate in any such proceeding.[46] Also, such parties may protest the utilization of area rate clauses even in the face of agreement among the parties to the contract as to the interpretation which should be ascribed to such clauses. In this event, however, the Commission advises that considerable weight will be given to the interpretation ascribed to the contract by its parties.

Because it is the Commission's general view that area rate clauses may be relied on by the parties to a contract as authority for an increase in rates to Natural Gas Policy Act statutory ceilings, and specifically because our analysis suggests that area rate clauses would appear to have been triggered at least with respect to the rates under sections 104 and 106(a) of the Natural Gas Policy Act, the Commission concludes that it is neither necessary nor appropriate to revise our blanket affidavit procedures provided in Commission Order Nos. 15 and 15-A (§ 154.94 of the Commission's regulations under the Natural Gas Act) other than to extend the date for filing a protest. That section of our regulations currently provides that "neither the filing of a blanket affidavit nor the acceptance for filing of such an affidavit by the Commission, will affect any person's contractual right to purchase natural gas at a rate which is less than the applicable maximum lawful price under the Natural Gas Policy Act."[47] Also, the ***Mobile-Sierra*** line of cases makes clear that a rate increase under the Natural Gas Act in the absence of contractual authority is a "nullity" whether the rate was accepted by the Commission or not.[48]

Accordingly, if it is ultimately determined on the basis of a final nonappealable order of this Commission, or if it is ultimately found by a court, that an area rate clause did not, in fact, provide the requisite contractual authority for the rate increase, the producer would be under the obligation to return the monies collected for which there did not exist contractual authority and, under standard PGA provisions, these monies would be required to be flowed-through to the consumer. It is our view, moreover, that the standard rate of interest applicable to refunds under Commission regulations would apply to any such amounts required to be paid back and flowed-through to purchasers. Accordingly, in any case in which a challenge is made to the utilization of or reliance on an area rate clause as authorization to collect the Natural Gas Policy Act statutory rates, it is unnecessary for the Commission to specifically suspend and require that the amounts in dispute be collected subject to refund.

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[46] The process of determining whether the subject contract authorizes the rate increase could take many forms. Some guidance can be gleaned from our handling of similar questions under the Federal Power Act. In those instances where a contract-based challenge is raised, the Commission has resolved the question in one of two ways. If the protest asserts that the contract language is sufficient to resolve the matter, then the Commission has in the past examined the language in light of its experience and the arguments raised in the protests and rendered a decision. Where, however, the protest asserts that the language itself is not sufficient and parol evidence is needed, for example, because action of the parties subsequent to execution of the contract has modified the contract or the contract is ambiguous, then the Commission has entertained additional pleadings on the contested matter. (*See*, *Gulf States Utilities* v. *FPC*, 518 F.2d 450 (D.C. Cir. 1975); *Appalachian Power Co.* v. *FPC*, 529 F.2d 342 (D.C. Cir. 1976); *Indiana & Michigan Electric Co.* v. *FPC*, 530 F.2d 1060 (D.C. Cir. 1976)). The Commission generally has not found it necessary to resort to formal, adjudicatory hearings to decide these cases but that course of action may be appropriate in some circumstances. A protest petition should make specific reference to the applicable producer rate schedule (i.e. contract), assert the basis for the protest, and supply such further information as the protestant believes will assist the Commission or is relevant to the question. How the Commission will proceed from that point to dispose of the case is a decision that can only be made on a case-by-case basis. Further, the Commission expresses no opinion at this time on the evidentiary standard that may be imposed or the standard of review that may be employed by the Commission in deciding these issues.

[47] Section 154.94(h)(7).

[48] *See*, n. 13, *supra* at 13.

Thus, the Commission will establish a general protest procedure in which parties in interest can petition the Commission for a specific determination as to whether a particular contractual clause constitutes the requisite authority to charge and collect Natural Gas Policy Act rates. In light of the administrative difficulties, complexities and general practical problems which attend the transitional period, the Commission will amend its protest procedures contained in § 154.94 to allow for filings of protests within the later of 90 days after filing of an affidavit, or May 1, 1979. Similarly, protest to interim and retroactive collection filings may be filed within the later of 90 days of the filing of notice to the Commission, or May 1, 1979.[53] The Commission, for practical administrative reasons and in order to give some certainty to these matters, will not entertain protests filed after that date. Of course, parties in interest may still be able to resort to the courts to seek resolution of the question.

2. Existing Intrastate Sales Contracts.

As a general matter, fixed price and indefinite price escalator clauses in existing intrastate contracts may permit escalation of the price under the contract in accordance with the terms of that contract. In a case where section 105(b)(1) of the Natural Gas Policy Act applies, escalator clauses may permit an increase in the contract price up to but not in excess of the current new natural gas price under section 102 of the Natural Gas Policy Act.[54] Questions of contract interpretation are left, in the first instance, to the parties to the contract. In the event of their disagreement, the question should be left to state courts to resolve.

Of course, where section 105(b)(1) applies, while the matter of contract interpretation of existing intrastate contracts is generally to be left to the parties, the parties cannot ascribe an interpretation to their contract which contradicts or is inconsistent with the terms of the contract as they were in effect on November 9, 1978 (the date of enactment of the Natural Gas Policy Act).

In order to give some guidance to the parties on how the Commission intends to discharge its administrative and enforcement responsibilities pursuant to section 501 of the Natural Gas Policy Act, the Commission believes it must responsibly address the question of the operation of FPC-type clauses. Consistent with our discussion and analysis of this matter concerning area rate clauses in interstate contracts of which FPC-type clauses are the functional equivalent, it is our view that the parties may interpret such clauses (consistent with their terms) as providing contractual authority to escalate to applicable Natural Gas Policy Act statutory prices.

Finally, because the Commission has revised its view concerning the operation of area rate clauses and FPC-type clauses in existing interstate and intrastate contracts, the Commission will not give further consideration at this time to the issues raised in the proposed rulemaking concerning the authority of the parties to these contracts to amend their terms. Such questions will be addressed in a subsequent interpretative order of the Commission.

IV. EFFECTIVE DATE

The amendments discussed above will be effective immediately, pursuant to a finding of good cause under 5 U.S.C. 553(d)(3). According to industry practice, producers, under ordinary circumstances, would have billed in *January 1979 for deliveries made in December 1978,* the effective date of the ceiling prices under the Natural Gas Policy Act. This order has a significant impact on the amount that parties may lawfully bill for such deliveries. The Commission believes it is important to inform parties to natural gas purchase contracts concerning the amounts they are permitted to collect at the earliest possible moment. Accordingly, we believe that good cause exists to make these amendments effective immediately.

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[53] The Commission notes that under the Natural Gas Act, a unilateral rate increase filing inconsistent with the applicable contract between the parties is invalid, and need not be suspended within 30 days after it is filed.

[54] If, however, the producer claims eligibility for a price higher than the 105(b)(1) price—*e.g.*, the price under section 108, escalator clauses may be relied on to obtain the higher price for that production which is determined to qualify for the higher price.

The Commission notes that the precise rules we are adopting have not been specifically included in a general notice of proposed rulemaking under 5 U.S.C. 553(b). However, the original version of § 270.205 was published on December 1, 1978, and the public has had opportunity to file comments since that time. Moreover, the Commission has separately requested comments concerning § 270.205, issued a separate notice of proposed rulemaking, and held oral argument on January 19, 1979 and February 27, 1979, confined solely to issues concerning the effect of the Natural Gas Policy Act on price escalator clauses in existing contracts. We believe that, through the above-described procedures, parties have received ample notice and have had sufficient opportunity to participate in the formulation of our decision.

APPENDIX

SUMMARY OF OTHER COMMENTS RESPECTING INTERSTATE CONTRACTS

This appendix attempts to identify other major comments which have been filed in this proceeding. The comments have addressed a number of issues in addition to that of contractual intent of the parties. Failure to refer to specific comments or arguments either in the body of the Commission's opinion or in this appendix should not be considered an indication that the comments have not been considered.

1. *The Area Rate Clause in Interstate Contracts.* Several members of Congress have addressed themselves to the issue of Congressional intent. Among these is Senator Pete Domenici of New Mexico.[1] The Senator stated that his understanding of the Congressional intent was for existing area rate clauses to provide contractual authorization for collection of all prices under the Natural Gas Policy Act. The Senator reasoned that since section 601(b)(1)(A) of the Natural Gas Policy Act declares the ceiling prices established therein rates just and reasonable, area rate clauses encompass these prices. The Senator also asserted that if producers are denied the ceiling prices under their existing contracts then those producers who drilled wells during 1977 and 1978 in reliance on the Commission's commitment to set a national rate for that biennium would be penalized.[2]

Representative Clarence Brown argues that section 101(b)(5) of the NGPA expressed Congressional intent to permit sellers to collect the highest price for which their natural gas is eligible.[3] To hold that escalation clauses prohibit such collection is, according to the Congressman, contrary to such Congressional intent.[4] The Congressman also represented that the proposed rule would prevent any natural gas which is now sold under existing interstate contracts from receiving the higher incentive prices established by sections 102, 103, 107 and 108. Congressman Brown asserts that as a result of the proposed rule, price disparity between natural gas sold in interstate and intrastate commerce will increase, in contravention of the Congressional policy of gradually abolishing the duality of price between the two markets.[5]

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[1] *See* Comments of Senator Pete Domenici filed January 18, 1979, in Docket No. RM79-3; *see also* Statement of Senator Pete Domenici filed February 27, 1979, in this docket, and oral argument February 27, 1979, Tr. 3-10.

[2] Statement of Senator Pete Domenici filed February 27, 1979, in Docket RM79-22, pp. 3, 4.

[3] Section 101(b)(5) reads as follows:

(5) SALES QUALIFYING UNDER MORE THAN ONE PROVISION: If any natural gas qualifies under more than one provision of this title providing for any maximum lawful price or for any exemption from such a price with respect to any first sale of such natural gas, the provision which could result in the highest price shall be applicable.

[4] Comments of Representative Clarence Brown filed January 18, 1979, in Docket No. RM79-3.

[5] *Id.*

Senator J. Bennett Johnston, Jr. also urged the Commission to permit sellers to collect Natural Gas Policy Act prices on the basis of area rate clauses. In support of this suggestion, he cites Congressional awareness that the Federal Power Commission had uniformly treated area rate clauses as authorizing payment and collection of new vintage rates.[6]

Congressman David Treen, in remarks made at the Commission's February 27 oral argument, also stated that the proposed rule runs counter to Congressional intent. He argued that the statute specifically addresses the question of escalator clauses in three circumstances alone. Congressman Treen suggests that the specific references in these three situations, combined with the failure of the NGPA to include a general provision regarding escalator clauses, is evidence of Congressional intent for existing interstate contracts to authorize collection of NGPA prices.[7]

Congressman John D. Dingell provided an analysis of the salient statutory provisions[8] and suggested several rationales upon which the Commission could permit collection of the NGPA ceiling prices. In his remarks, Congressman Dingell noted that the section 104 prices were designed to take the FPC determined wellhead prices and keep them constant in real dollars by escalating the prices monthly to account for inflation. He urged the Commission to construe area rate clauses as authorizing the collection of the section 104 prices. Chairman Dingell also noted that the incentive prices under sections 102, 103 and 107 would apply to natural gas determined to qualify for those prices. This natural gas would no longer be subject to the provisions and requirements of the Natural Gas Act pursuant to section 601. Therefore, he believes that even "impermissible" clauses can operate to authorize collection of such prices. Contractual amendments would also be permitted. Finally, with regard to section 108, the Congressman would suggest that area rate clauses are triggered to permit collection of the 108 price under a reading of sections 101(b)(6) and 601(b)(1).[9]

The Secretary of Energy, James R. Schlesinger, also filed comments in this proceeding discussing Congressional intent.[10] The Secretary stated that based upon the policy purposes of the statute (to create a national market as well as to provide increased domestic prices) the Commission should not interpret area rate clauses as proposed in the rule. Rather, the Secretary stated, that by force of the Commission's own regulations there was only one alternative for producers to utilize to contract for higher prices in the future: area rate clauses. The Secretary noted that all studies anticipated that these clauses would permit collection of the ceiling prices, including section 108 prices but especially section 104 prices.

Representative Toby Moffett[11] and Senator Jim Sasser,[12] on the other hand, support the Commission's proposed rule as it applies to area rate clauses in interstate contracts. Congressman Moffett states that the proposal is consistent with Congressional intent as expressed on page 83 of the Statement of Managers. He further suggests that incentive prices, as embodied in sections 102, 103, 107 and 108 of the NGPA, are not applicable to currently flowing gas.[13] Senator Sasser cites the Conference Report for the proposition that the statutory rates are only ceiling prices.[14]

Other parties cited Congressional intent in support of the proposed rule. For example, the Public Utilities Commission of the State of California referred to the discussion at page 83 of the Statement of Managers as evidence that "the bill's drafters were familiar with and approved of the bar against indefinite price escalator clauses in interstate contracts as then enforced by the Commission." [15] Comments filed by a group of gas consumers cite section 101(b)(9) of the statute as evidence that Congress did not intend to supersede contract prices,[16] and argue that area rate clauses do not permit collection of maximum lawful prices under the Natural Gas Policy Act.

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[6] Comments of Senator J. Bennett Johnston, Jr. filed January 18, 1979, in Docket No. RM79-3.

[7] Oral argument February 27, 1979, Tr. 21-23.

[8] Comments filed January 19, 1979, in Docket No. RM79-3.

[9] *Id.*

[10] Comments of James R. Schlesinger, Secretary of Energy filed February 26, 1979 in Docket No. RM79-3.

[11] Comments of Representative Toby Moffett filed February 27, 1979.

[12] Comments of Senator Jim Sasser filed February 27, 1979.

[13] Comments of Representative Toby Moffett, at p. 1.

[14] Comments of Senator Jim Sasser, at p. 2.

2. *Continued Natural Gas Act Jurisdiction.* In response to comments by many of the participants in this proceeding,[17] we expressly note the effect of section 601(a)(1) of the Natural Gas Policy Act on certain types of committed or dedicated natural gas. That provision provides that the Commission's Natural Gas Act jurisdiction over committed or dedicated natural gas ceases as to first sales under sections 102(c), 103(c) and 107(c) of the statute. Therefore, once a determination of eligibility under the above sections becomes final, the Commission's authority under the Natural Gas Act to limit or otherwise regulate the operation of contractual provisions terminates. The comments point out that this result applies both to previously impermissible clauses and area rate clauses.

3. *Variant Clauses.* Reference in the proposed rule to "variant clauses" has engendered considerable comment. The original Commission view was that a "variant clause"—any escalation provision that does not precisely reflect the precise language of § 154.93(b-1)—was inoperative to the extent its scope exceeded that of the permissible area rate clause.

In response to the comments received, the order has been revised to permit "variant clauses", which by their terms are triggered by passage of the Natural Gas Policy Act or which provide for escalation to the highest applicable rate prescribed by legislation to be operative according to their terms.[18] The notice issued on February 13, 1979 suggested that such clauses were in violation of § 154.93, and therefore would not be given effect.

4. *Contract Amendment.* The Commission's Notice of Proposed Rulemaking stated that although area rate clauses did not constitute contractual authorization for the statutory ceiling prices, the parties to existing interstate contracts could amend their agreements to provide for the payment and collection of any applicable maximum lawful price. The Commission further provided that any such amendment would be permitted to operate retroactively to December 1, 1978, and that interstate pipelines would be permitted to pass through increased costs attributable to contract amendments so long as the modification was agreed to in arms-length bargaining, and provided the Commission did not find "fraud, abuse or similar grounds" existed.

This particular aspect of our proposal has been the subject of a great deal of critical comment. Representative Toby Moffett stated that our "proposals allowing retroactive treatment to December 1, 1978 raise serious problems. The legislative history and the views expressed by Conferees in public meetings showed a strong desire to protect contract sanctity." [19] The Congressman further suggested that it is "unreasonable to expect customers to pay additional prices for gas already delivered." [20]

Other criticism expressed concern from a different point of view. For example, the New York Public Service Commission, citing the *Mobile-Sierra* doctrine, argued "[I]t is clear that contractually authorized rate increases cannot be made effective retrospectively and * * * only the filed rate can be charged." [21] The Michigan

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[15] Comments of the Public Utilities Commission of the State of California, filed February 27, 1979 at 3.

[16] Comments of Indicated Intrastate and Interstate Gas Consumers, filed in Docket No. RM79-3, Attachment B at 2.

[17] *See, e.g.,* New York Public Service Commission comments filed February 27, 1979 at 7; *see also,* Statement of Shell Oil Company filed February 27, 1979, at 24-26; Statement of the Honorable John D. Dingell filed January 19, 1979.

[18] *See,* Comments of the New York Public Service Commission filed February 26, 1979 at 7. *See also,* Comments of Chevron, U.S.A., Inc., filed February 27, 1979, at 6.

[19] Comments of Representative Toby Moffett, filed February 27, 1979 at 2.

[20] *Id.*

[21] Comments of the New York Public Service Commission filed February 26, 1979 at 8, citing *Montana-Dakota Utilities Co. v. Northwestern Public Service Co.,* 341 U.S. 246 (1951).

Public Service Commission[22] and others[23] made the same argument. New York also argues that the retroactive amendment proposal is inconsistent with the NGPA and other Interim Regulations issued thereunder. New York states that, although section 601(a)(1)(B) of the statute makes the Natural Gas Act inapplicable to certain committed or dedicated gas, the Natural Gas Policy Act itself requires that there be contractual authorization at the time deliveries of gas are made. New York further states that, although the Conference Report (at page 120) mentions retroactive collection of Natural Gas Policy Act ceiling prices in certain circumstances, it does not permit the Commission to authorize retroactive contract amendments.[24] New York also rejects the FERC's attempt to justify retroactively on equitable grounds.[25]

Laclede Gas Company stated that the Commission should not rely upon contractual amendment to circumvent its policy determination. Laclede urges the Commission to decide the issue unequivocally and "not pass the responsibility, and liability, for decision on to the Nation's pipelines."[26]

5. *Pipeline Passthrough.* Many participants have criticized the proposed rule's approach to pipeline passthrough of increased costs resulting from contract amendments. The Commission proposed that it would permit passthrough of these costs so long as the modifications were the result of "arms-length bargaining," and provided that there was no "fraud, abuse, or similar grounds". Comments on this issue range from assertions that the rule, although conceptually sound, provides insufficient guidance, to statements that the proposed policy is unjustifiable on its merits.

Associated Gas Distrubutors (AGD) argue that the Commission should provide a working definition of arms-length bargaining which among other things recognizes that adequate consideration is needed to support a bona fide contract amendment.[27] AGD also would place the burden of showing adequate consideration on the producer-seller. Alabama Gas Corporation and Indicated Intrastate and Interstate Gas Consumers also support the view that adequate consideration is necessary to effect a valid contract amendment.[28]

The majority of interstate pipelines filing comments in this proceeding agreed that the intent of the parties to the contract was controlling. However, may of the pipelines were concerned that they be guaranteed the passthrough of payments made pursuant to a contractual amendment. The interstate pipelines were also concerned with the meaning of the term "arms-length" transactions.[29]

The Commission has reconsidered its opinion in light of the comments filed and in consideration of the Commission's opinion that contractual intent of the parties control. By effectuating the intent of the parties, the need for contract amendment decreases substantially. The Notice of Proposed Rulemaking would have permitted such amendments to operate retroactively to December 1, 1978, provided the parties agreed to such retroactivity. The Commission explained that fairness to the parties required that we permit such retroactivity. Several comments expressed the view that the Commission would be acting beyond the scope of its authority in permitting contract amendments to operate retroactively. The action we are taking today, in giving effect to the intent of the parties, obviates the need to address the retroactivity of any amendment.

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[22] Comments of the State of Michigan and the Michigan Public Service Commission filed February 27, 1979 at 5-7.

[23] Comments of the South Dakota Public Utilities Commission and the Minnesota Public Service Commission, filed January 31, 1979 in Docket No. RM79-3, at 2, 3.

[24] New York Comments, *supra*, at 9, 10.

[25] *Id.* at 9. New York is referring to the Commission's statement in the notice of proposed rulemaking that since the enunciation of the Commission's policy concerning area rate clauses did not come until after the effective date of the NGPA, contract amendments made in response to the rule should be permitted to operate retroactively to that date.

[26] Comments of Laclede Gas Company filed February 27, 1979, in Docket No. RM79-22, p. 3.

[27] *See,* Comments of Associated Gas Distributors filed February 27, 1979 in Docket NO: RM79-22.

[28] *See,* Comments of Alabama Gas Corporation filed February 27, 1979 in Docket No. RM79-22, and Comments of Indicated Intrastate and Interstate Gas Consumers Regarding Proposed Rules filed February 27, 1979 in Docket No. RM79-22.

[29] *See, e.g.,* Natural Gas Pipeline Company of America filed February 27, 1979 in Docket No. RM79-22; Comments of Texas Gas Transmission Corporation filed February 27, 1979 in Docket No. RM79-22 and Comments of Interstate Natural Gas Association of America filed February 27, 1979 in Docket No. RM79-22.

6. *State Jurisdiction.* The State of Michigan and the Michigan Public Service Commission (Michigan), both in written comments[30] and at oral argument, have suggested that the FERC speak to the relationship of our action in this docket to the jurisdiction of state regulatory agencies. Michigan states that the proposed rule fails to acknowledge the jurisdiction of the states to restrict or regulate the operation of escalator clauses in interstate commerce. The order of the Commission does not deal with this question, but we wish to make clear, if there is any doubt, it is not our intention to intrude into the jurisdiction that the Congress has left to the states to establish lower ceiling prices with respect to production occurring in that state.[31]

7. *Comments on Intrastate Contracts.* Several parties have commented concerning the application of the proposed rule and the Commission's underlying discussion to existing intrastate contracts. The Southern Union Company, a New Mexico distribution company, asserts that the effect of the proposed rule will be to discourage production on undeveloped acreage which is subject to existing intrastate contracts. Southern Union states that it is a party to a number of contracts with no escalation provisions, or with nominal fixed escalations. If such a contract is subject to section 105(b)(1) of the Natural Gas Policy Act, it may not be amended to effect a price increase above the price paid on November 9, 1978. Accordingly, Southern Union argues a producer would be unwilling to dedicate additional undeveloped acreage to the contract.[32]

Indicated Consumers disagree with the proposed rule to the extent that it would permit a seller of gas to receive a price above the section 102 price. Indicated Consumers argue that section 105 sets a mandatory price ceiling which may not be exceeded even for particular wells which qualify under various other Title I wellhead pricing provisions. Indicated Consumers further argue that to the extent the Commission leaves interpretation of contracts to the parties it is violating section 501(a) of the Natural Gas Policy Act which calls for the FERC to administer the statute.

Mountain Fuel Supply Company states that in some circumstances the proposed rule would discriminate against the intrastate market. If a producer has an intrastate contract subject to section 105(b)(1) of the Natural Gas Policy Act that contains an FPC clause and no other escalation provision, he would be unable to amend his contract to collect higher statutory prices. An interstate seller could, however, amend his contract and collect prices under sections 102, 103, 107 and 108.[33] On a related issue, Hawthorne Oil and Gas Corporation takes exception to our proposed interpretation of FPC clauses which refer to "successor governmental authority".[34] Northwest Arkansas Producers Group suggests that this interpretation is inconsistent with the general intention of the Commission, expressed at page 40 of the Notice, to leave initial interpretation of intrastate contracts to the parties.[35]

Mesa Petroleum Company also criticized this interpretation. Mesa asserts that it is illogical for the Commission to interpret FPC clauses in intrastate contracts in the same way as area rate clauses in interstate contracts. To make such an interpretation merely for consistency's sake is, according to Mesa, to ignore the actual intent of the parties. While intent of the parties to an interstate contract may be construed in light of FPC regulations, such is not the case with intrastate contracts. Mesa states, "Parties negotiating an intrastate contract were not inhibited by * * * regulatory restraints; their concern was to contract for the best possible price initially and, during the term of the contract, a price at least as high as any seller in the interstate market was permitted charge."[26]

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[30] Comments filed February 27, 1979, in Docket No. RM79-22 at 7, 8; Tr. at 295.

[31] See section 602, Natural Gas Policy Act.

[32] Comments of Southern Union Company, filed February 27, 1979, at 2-4.

[33] Comments of Mountain Fuel Supply Company filed February 27, 1979, at 6. Lone Star Gas Company also raised this question in its comments filed February 27, 1979, at page 4.

[34] Comments of Hawthorne Oil and Gas Corporation, filed February 26, 1979.

[35] Comments of Northwest Arkansas Producer Group, filed February 26, 1979, at 3.

Finally, as the order notes, the Commission has revised its view concerning the operation of area rate clauses and FPC-type clauses in existing interstate and intrastate contracts, therefore, the Commission will not give further consideration at this time to the issues raised in the proposed rulemaking concerning the authority of the parties to these contracts to amend their terms. Such questions will be addressed in a subsequent interpretative order of the Commission.

(Natural Gas Act, as amended.) (15 U.S.C. 717, *et seq.*, Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, E.O. 12009, 42 FR 46267)

In consideration of the foregoing, Part 154 of Subchapter E and Parts 270 and 273 of Subchapter H, Chapter I Title 18, Code of Federal Regulations, are amended as set forth below, effective immediately.

By the Commission. Commissioner Holden voted no.

KENNETH F. PLUMB,
Secretary.

[¶ 30,041]

44 F. R. 18007 (March 26, 1979).

[Docket No. RM79-31]

PART 276—REPORTS

AGENCY: Federal Energy Regulatory Commission.

ACTION: Amendment to interim regulations.

SUMMARY: This document extends for 2 months the filing dates for reports for first sales of natural gas under the Natural Gas Policy Act of 1978 (43 FR 56448, December 1, 1978).

FOR FURTHER INFORMATION CONTACT:

Kenneth F. Plumb, Secretary; 825 N. Capitol St., N.E., Washington, D.C. 20426; 202 275-4166.

SUPPLEMENTARY INFORMATION: On December 1, 1978, the Federal Energy Regulatory Commission (Commission) issued interim regulations implementing the Natural Gas Policy Act of 1978 (NGPA). Part 276 of the interim regulations set forth reporting requirements applicable to first sales of natural gas sold pursuant to the provisions of Subparts E, F, and I of Part 271 which implement Sections 105, 106(b), and 109 of the NGPA. These provisions deal with first sales of natural gas under existing intrastate contracts, intrastate rollover contracts, as well as first sales of other categories of natural gas.

The reports required to be filed pursuant to Part 276 were due on or before March 1, 1979, followed by an annual report each March 1st thereafter. Such reports were to be compiled in accordance with forms and instructions to be issued by the Commission.

Inasmuch as the requisite forms and instructions have not been promulgated to date, good cause exists to amend Part 276 of the interim regulations to extend the date for filing of the initial reports from March 1, 1979 to May 1, 1979. The Commission intends to issue an order promulgating these forms and instructions in the near future.

(Natural Gas Act, as amended, 15 U.S.C. 717, *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. 791, *et seq.*, Federal Energy Administration Act, 15 U.S.C. 761, *et seq.*, Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, Department of Energy Organization Act, Pub. L. 95-91, E. O. 12009, 42 F.R. 46267).

In consideration of the foregoing, Part 276 of Subchapter H, Chapter I,

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[26] Comments of Mesa Petroleum Company, filed February 26, 1979, at 5.

Title 18, Code of Federal Regulations, is amended as set forth below, effective immediately.

By the Commission.

KENNETH F. PLUMB,
Secretary.

[¶ 30,042]

44 F. R. 18647 (March 29, 1979).

[Docket No. RM79-30]

SUBCHAPTER H—REGULATION OF NATURAL GAS SALES UNDER THE NATURAL GAS POLICY ACT OF 1978

PART 276—REPORTS

Subpart A—Reports for Sales of Natural Gas Under Sections 105, 106(b), and 109 of the NGPA

FINAL REGULATIONS AMENDING AND CLARIFYING AND PROMULGATING FERC FORMS 122, 123, AND 124 WITH ACCOMPANYING AFFIDAVITS AND INSTRUCTIONS

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final Regulations.

SUMMARY: The Natural Gas Policy Act of 1978 (NGPA), enacted November 9, 1978 took effect with respect to certain first sales of natural gas delivered on or after December 1, 1978. Interim regulations implementing the NGPA were issued on December 1, 1978, (43 FR 56448) and called for written comments by January 31, 1979.

On February 2, 1979, the due date for initial reports under Part 276 of Subchapter H of the Interim Regulations was amended.

The regulations under Part 276 are amended further and are now issued as final regulations under the NGPA. The amendments revise reporting periods and deadlines, change record retention requirements, and clarify or otherwise change certain other reporting requirements. In addition, FERC Forms 122, 123, and 124 and accompanying affidavits and instructions are promulgated as part of the reports system of Part 276.

EFFECTIVE DATE: March 23, 1979.

FOR FURTHER INFORMATION CONTACT:

Scott E. Koves, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 275-4808.

Brooks Carter, Office of Pipeline and Produce Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 275-4557.

MARCH 23, 1979.

I. BACKGROUND

On December 1, 1978, the Federal Energy Regulatory Commission (Commission) issued interim regulations implementing the Natural Gas Policy Act of 1978 (NGPA). (43 FR 56448) Part 276 of the interim regulations sets forth reporting requirements applicable to first sales of natural gas sold pursuant to the provisions of Subparts E, F, and I of Part 271 which implement Sections 105, 106(b), and 109 of the NGPA. These provisions deal with first sales of natural gas under existing intrastate contracts, intrastate rollover contracts, as well as first sales of other categories of natural gas.

Part 276 created a general reporting obligation on first sellers of natural gas qualifying under Sections 105, 106(b) and 109 of the NGPA. An initial report was to be filed March 1, 1979,[1] followed by an annual report each March 1st thereafter. Two exceptions to the general reporting rule were established in the case of sales under either Sections 105 or 106(b) of the NGPA. The first exception applies to persons who sold less than 10,000 MMcf of natural gas between December 1, 1977, and November 30, 1978.

The second exception applies to first sellers of natural gas who sell to either inter- or intrastate pipelines. In the first exception, the first seller has an option to forgo the general reporting obligation and file an oath undertaking instead. In the case of the second exception, there is no option; the pipeline is obligated to make the general report filings and the first seller, regardless of the amount of sales it makes, need only file an oath undertaking.

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[1] By order issued February 2, 1979 in Docket No. RM79-3, Part 276 was amended to extend the deadline for initial reports from March 1, 1979 to May 1, 1979.

Upon further analysis of the data needs of a viable compliance and enforcement program versus the reporting burdens on respondents, initial reporting forms with accompanying detailed instructions were prepared and submitted to the Office of Management and Budget (OMB). The forms, designated FERC Forms 122, 123, and 124, were approved by OMB on December 29, 1978. These forms are now designed to be easily completed by the respondent, suitable for automated data processing (ADP) procedures, and yet provide the types of information necessary to monitor the subject sales and assure compliance with the NGPA. Revisions to the forms and instructions that result from our order today were approved by OMB on March 12, 1979. The forms, oaths, and instructions, attached as Appendix A to this order, will be reproduced for distribution following today's order.

In addition to promulgating oath affidavits and Forms 122, 123, and 124, our order today revises the reporting obligations of Part 276 in several respects: (1) It extends the due date for the first Part 276 reports to June 1, 1979. (2) It revises the reporting period to coincide with the calendar year. (3) It extends the annual reporting deadline to April 1 of each year beginning in 1980. (4) It deletes § 276.102(a)(1)(vi) which called for the contract price on December 31, 1984. (5) It changes the commencement date of the period during which records must be retained. (6) It amends the exceptions in § 276.101(b) for purposes of clarification. (7) It adds two new exceptions to § 276.101 by adding new paragraphs (b)(3) and (b)(4) relating respectively to small volume direct sales and sales by States. (8) It adds a new § 276.106 which promulgates reduced reporting obligations relative to small volume direct sales. (9) It amends § 276.104(d)(2) by deleting the previous condition respecting dedication to interstate commerce. (10) It adds a new section, § 276.109, *Forms, instructions and affidavits,* which specifies the particular Part 276 forms and affidavits to be used by respondents.

II. SUMMARY OF FORMS

Pursuant to today's order, the Commission's reporting system under Part 276 of the regulations under the NGPA now includes the following forms:

FERC Form 122—Report of First Sales of Natural Gas Under Section 109 of NGPA—Other Categories of Natural Gas.

FERC Form 123—Initial report of First Sales of Natural Gas Under Section 105 of NGPA—Existing Intrastate Contracts.

FERC Form 124—Report of First Sales of Natural Gas Under Section 106(b) of NGPA—Intrastate Rollover Contracts.

A fourth form, FERC Form 125, will be promulgated later and will be used beginning with the 1980 report to provide the Commission with an annual update of contract information submitted in FERC Forms 122, 123, and 124. Accompanying these forms is a title page on which the respondent will identify itself, sign an affidavit and indicate which of the forms is being filed. The forms also are accompanied by a detailed set of instructions and definitions of terms used in the forms.

FERC Form 122 is an initial report of first sales under Section 109 of the NGPA. The form calls for an identification of the sale including the date the contract was entered into, the purchaser, the highest contract price during the reporting period, average Btu content, and sales volume during the reporting period. In addition, in order to fully comply with § 276.104 of the interim regulations, the instructions indicate that respondents must accompany Form 122 with an affidavit and certain supporting statements that specify the basis for qualification of the sale under Section 109 of NGPA. Certain other identifying information is also called for which will aid in the Commission's review of such sales.

FERC Form 123 is a one-time report for first sales of natural gas qualifying under Section 105 of the NGPA, which are sales under "existing intrastate contracts" as that term is defined in § 270.102(b)(8) of the interim regulations. In addition to basic buyer, seller, and contract identification, Form 123 requires a specification of the contract price on November 9, the highest contract price during the reporting period, the contract term, the average Btu content of the gas and the volume delivered during the reporting period. Also, as required by § 276.102 of the interim regulations, the filing must include an affidavit and if the contract price on November 9, 1978, is $2.060 per MMBtu or less, a copy or summary of the contract price escalator terms.

Based on discussions with state jurisdictional agencies, it is estimated that approximately 50,000 contracts will be reported on FERC Form 123. In most cases the respondent will be a pipeline since sellers must report only those sales to non-pipeline purchasers. The total number of respondents is therefore not expected to exceed 750.

FERC Form 124 is an initial report designed to collect data on sales qualifying under Section 106(b) of the NGPA, which are "intrastate rollover contracts," as defined in § 270.102(b)(11) of the interim regulations. This form calls for information identifying the sale, including the date the expired contract was entered into, and the last price paid under the expired contract. The Form 124 also calls for information on the new (rollover) contract which includes the sale commencement date and the initial price, average Btu content and sales volumes during the report period. Because the first Form 124 reports to be filed by June 1, 1979, only cover a reporting period consisting of the month of December 1978, the initial price paid under the rollover contract will be deemed sufficient in lieu of the highest price paid for that month, as required by § 276.103(b). In the future, the highest price paid during the reporting period will be reported on the FERC Form 125. In addition, as with the other forms, the filing is required by § 271.103 to include an affidavit and certain other information.

The reporting population for FERC Form 124 is expected to be the same as the respondent population for Form 123. It is estimated that approximately 2,000 intrastate contracts in existence on November 9, 1978, will "roll over" in each subsequent annual reporting period.

In the case of all three forms, annual reports will be required commencing with the 1980 report. A separate FERC Form 125 will be developed at a later time for this purpose. Respondent may exclude any information which has been included in a previous report. However, pursuant to §§ 276.102(b) and 276.103(b), the respondent will be required to report the sales volume during the report period, the highest price charged and collected, and the month in which the highest price was charged. In addition Forms 122 and 124 must also be submitted for initial reporting of sales that qualify in the future under Sections 106(b) or 109 of the NGPA.

In addition to supporting a monitoring and compliance program, the information gathered on Forms 122, 123, and 124 will be useful in preparing statistical summaries. Separate analyses are to be conducted for sales under Section 109 and for contracts that initially qualify under Section 106(b) during the reporting period.

It should be noted that data submitted on FERC Forms 122, 123, and 124 will be held confidential only to the extent that they are determined to be within the exemption for trade secrets and confidential commercial information as specified in the Freedom of Information Act, 5 U.S.C. 552(b)(4).

III. SUMMARY OF COMMENTS AND REVISIONS TO PART 276

A. PERSONS REQUIRED TO FILE REPORTS AND OATHS

Several parties requested clarification of the term "seller" and stated that the regulations could be interpreted to require all parties with an interest in the gas, even royalty owners, to file a report. One party recommended that treatment similar to § 154.91 of the Commission's regulations should be accorded to interest owners under one contract.

Although maximum lawful prices under the NGPA apply to any person who makes a first sale of natural gas, we do not consider it necessary for every interest owner to file a separate report or to be identified separately in a combined report. From a compliance viewpoint, it is the sales transactions which are important, and the parties of significance are those persons responsible for administering the sales. We are aware that there are many different contractual arrangements and payment methods involved in the sale of natural gas and that many of the producers and pipelines now under the jurisdiction of the NGPA have not previously been required to file reports with the Commission.

We therefore have specified in the attached instruction sheets the following general reporting requirements for the Part 276 reports. Royalty interest owners will not be required to report except where royalty payments taken in kind are subsequently sold in first sale transactions. In the case of a report filed by a seller for sales to nonpipeline purchasers, working interest owners who are nonsignatories to the gas sales contract are not required to report. One signatory party under the contract may be designated to file on behalf of all co-owners of interest in sales under the contract, including all other signatory parties. The report shall include total sales under the contract including sales of all signatories and non-signatories to the contract. Except in the case of a report of intrastate rollover contracts, where there is more than one co-owner under a single contract, it will not be necessary to identify the other co-owners included in the report. However, all working interest owners who are signatory parties to a gas sales contract will still be required to file an oath statement, even where the report is filed by another signatory party on their behalf.

In the case of reports filed by pipelines under §§ 276.102 or 276.103 the pipeline shall report price and volume information for each contract. Where there is more than one interest owner under a single contract, only one seller must be identified—either the operator if a signatory, or the major interest owner.

Comments were received from producers who argued that the oath requirement in § 276.102(e) is "inconsistent with the general pattern of the remainder of the regulations." They suggested that the oath statement should be filed by the seller himself, rather than an official of the seller as that section requires. We shall reject this suggestion. First, we cannot agree that the "general pattern" of the remainder of the regulations, a fact wholly irrelevant to this issue, dictates that the seller rather than a responsible official of the seller should file oath statements. Second, it is not clear who would file on behalf of a seller that is a corporation, trust, partnership or some other form of business entity, other than a responsible official of that entity. Third, if the seller is an individual, then the regulation requires him to sign the oath statement.

We would note at this point that the forms package includes four affidavits to be used for purposes of filing the appropriate oath statements in Part 276. One covers the oaths required by §§ 276.102 and 276.103 while the other three are separate oaths for § 276.104, § 276.105, and § 276.106. In addition, a responsible official of the party actually filing reports under Part 276 must sign an oath included as part of the title page to the reports that to the best of his information, knowledge and belief all information submitted in the report is true.

A state agency questioned whether states are required to file Part 276 reports and oath statements. They are not. Even though states are included in the definition of "person" under section 2(26) of the NGPA, we believe states should be accorded a presumption of regularity. We have therefore included a new subparagraph (b)(4) to § 276.101(b) which exempts state governments from the general reporting and oath obligations under Part 276. State governments that make first sales of natural gas under sections 105, 106(b) or 109 of the NGPA shall only be required to comply with the record retention obligations of § 276.108.

Producers have also requested an exemption from the filing requirements for sales to an "independent producer" and to a "first sale" reseller, including sales to processing plants under percentage sales contracts, asserting that regulation of the resale automatically regulates sales prior to the resale. Percentage sale contracts generally involve a sale to the operator of a processing plant at a price which is a percentage of the net proceeds from the resale of the residue gas and may appear in various forms.

Even though it is arguable that some degree of duplicate regulation resluts, we cannot abrogate our responsibilities under sections 105 and 106(b) of the NGPA to scrutinize first sales on a contract-by-contract basis. Where there are multiple parties under the same contract, our obligations can be met by requiring only one such person to report. But where there are multiple contracts, Sections 105 and 106(b) of the NGPA mandate compliance by the sales under each contract with the maximum lawful price provisions of the act.

Accordingly, we fail to find good cause to exempt persons selling to processing plants or other resellers from the reporting requirements of Part 276. As a practical matter, many of these sellers will qualify under the exemption in § 276.101(b)(1) and thus will only be required to file an oath statement.

In this regard we perceive the need to clarify how percentage sellers are to report their "contract price" on November 9, 1978, for purposes of Part 276 reports and oath statements. Percentage sale contracts have no specific price stipulated under the terms of the contract. Rather, they are generally based on the recovery of a fixed or volumetrically-determined percentage of net proceeds received from the sale at a plant tailgate of a mix of residue gas derived from many different producers. A "contract price" on November 9, 1978, might be computed by dividing sales volumes attributable to the percentage seller on that date into the revenue received for sales on that date. Such a computed "contract price" could change from day-to-day depending on various factors including the mix of resale prices at the plant tailgate and the price of liquids.

Accordingly, we find it appropriate to simplify the reporting of percentage proceeds sales by permitting the percentage received from the plant to be reported in lieu of a "contract price". Volumes to be reported shall be residue gas volumes.

Another comment requested clarification of how the 10,000 MMCF sales cutoff is to be determined for purposes of § 275.101(b)(1). This qualification concerns all sales by the respondent or any affiliate thereof, including all resales and including all sales as signatories or non-signatories to sales contracts and whether in inter- or intrastate commerce. Royalty interests in sales shall not be considered. However, where royalty gas taken in kind is later sold, such sales shall be included in the 10,000 MMCF determination. Part II-E of the instructions attached to the Part 276 reports now includes this clarification.

We also received several comments via the Commission's "Hotline" that expressed confusion as to the interrelationship between the exceptions created in paragraphs (b)(1) and (b)(2) in § 276.101. We have revised § 276.101(b) to make it clear that the exception in paragraph (b)(1) only applies in the case of a sale to someone other than a pipeline.

Two comments from large producers suggested that sellers involved in certain small volume direct or "field sales" should also be exempted from the general Part 276 reporting obligations and should only be required to file oath statements.

Under the NGPA, all first sales, however small, are subject to maximum lawful prices. However, we are also cognizant of the fact there are many thousands of small volume sales, such as for irrigation purposes, where the purchaser is the end-user. There is a point where administrative infeasibility outweighs the need to obtain full reports for each such sale. One comment suggests a cutoff of 500 mcf per day or a term of less than one year to non-pipeline purchasers for consumption.

Recognizing that any cutoff is somewhat arbitrary, we shall create a new exception to the general Part 276 reporting obligations and permit respondents to file blanket reports covering all direct sales to non-pipelines made during the reporting period where the average of the total sales by all persons under each contract covering such sales did not exceed an average of 60 mcf per day during the previous calendar year. Data obtained from various producers and from reviewing

Form 45 reports indicates that this cutoff will account for most, if not all, of the typical small volume direct sales which sales volumes make up only a small percentage of the total sales volumes in the United States.

We have added a new subparagraph (b)(3) to § 276.101(b) which permits a respondent to elect to forego the general Part 276 reporting obligations for such exempt small direct sales and to file a simplified and greatly reduced report pursuant to new § 276.106. Persons making such exempt sales will be permitted to aggregate these sales in a single report consisting of a title page and attached affidavits and need only report total exempt volumes sold, total revenues received for such sales, and the total number of contracts covered by the report. It should be noted that this exemption only applies to the particular sales that qualify. Persons making such sales may still be obligated to file reports covering other sales pursuant to the other provisions of Part 276.

For the purposes of determining whether this exemption applies with respect to the initial reports due June 1, 1979, the volumes sold during the full calendar year 1978 are to be considered.

Another comment dealing with § 276.101(b)(2) suggested that pipelines should only be required to report in the case of large sales, for example, greater than 1 Bcf per year. We decline to do so. Such a further condition would unduly complicate the reporting requirements and would run counter to the purpose of eliminating reporting burdens on small companies.

Finally, several pipeline company comments suggested that §§ 276.101(b)(2), 276.102(d), and 276.103(d), could be read to require duplicate reports. Only one report is required. Section 276.101(b)(2) only designates who is to file reports in certain cases. The actual reporting requirements are designated in §§ 276.102 and 276.103, whichever is applicable.

B. BASIS OF REPORTING

One pipeline company commented that it is unable to allocate volumes by contract when several contracts are involved in the purchase of gas from a well or unit and it is the operator who distributes the proceeds of the sale. Where volumes cannot be allocated by contract, the total volume may be included in the entry for the operator. However, all other contracts must be listed, including price data for each, following the entry for the operator.

One commentor suggested that the pipeline purchaser be permitted to report volumes and contract information by purchase point identifying number (*i.e.*, well, plant outlet, or gathering system) instead of by contract. Each station number identifies a particular stream of gas being purchased, and price and contract information for each seller is identical except for contract date.

Since maximum lawful prices under sections 105 and 106(b) of the NGPA are determined as a function of either the contract price on a specific date or the price under the terms of the contract in effect on a specific date, it follows that a reporting system for compliance purposes should be based on contract data. We recognize that many intrastate respondents, absent prior Federal reporting requirements, have not developed their recordkeeping systems in accordance with uniform reporting standards. However, we believe there are only a few cases where companies will be unable to report on a contract basis. In those cases, respondents may petition the Commission under section 502(c) of the NGPA for an alternative filing procedure more adaptable to their recordkeeping system and reporting capability. However, any such requests are subject to prior approval and will not be granted where information which the Commission deems essential to its compliance effort is omitted.

Finally, one company requested clarification of the pressure base to be used in reporting price and volume information. The appropriate pressure base for all respondents is 14.73 psia at a standard temperature of 60 degrees Fahrenheit. The attached instructions contain conversion factors to be used in converting to this pressure base.

C. CONTRACT PRICE FOR EXISTING INTRASTATE CONTRACTS

One commentor argued that the requirements of § 276.102 do not recognize the different pricing criteria established in §§ 271.502(a) and

271.502(b) in that only the contract price on November 9, 1978, is called for in § 276.102 without a requirement for reporting the price under the terms of the contract on November 9, 1978. Since the "contract price" on November 9, 1978 (as defined in § 271.504(a)) means the price paid or that would have been paid on November 9, 1978, and that since such "contract price" must be computed for that date according to the terms of the existing contract as they appeared on that date, there is no difference between the "contract price" on November 9, 1978, and the price on November 9, 1978 under the terms of the existing contract on November 9, 1978. Though the "price under the terms of the existing contract" may later change, the fact remains that *on* November 9, 1978, the two terms mean the same thing.

However, following the language of section 105(b) of the NGPA, it is the term "contract price" on November 9, 1978, which governs whether the general rule of § 271.502(a) or the exception of § 271.502(b) applies. The contract price is therefore a significant item of information which should be reported under § 276.102.

Another commentor suggested that we add contract prices on November 8 and 10, 1978, to the list of items required in § 276.102. We shall decline to do so. The key date for purposes of compliance is November 9, 1978.

Several other comments noted that the contract price on December 31, 1984, cannot be determined with certainty if the contract contains indefinite price escalator provisions. We agree that in many cases the price on this date will be indeterminate. Since the highest price for each contract is reported annually, better data on intrastate contract prices on December 31, 1984, can be obtained from reports submitted in subsequent years. Accordingly, we shall delete § 276.102(a)(1)(vi) which called for the contract price on December 31, 1984.

D. CONTRACT PRICE ESCALATOR TERMS FOR EXISTING INTRASTATE CONTRACTS

One comment suggested that a format similar to that used on FERC Form 45 be used to summarize price escalator terms. Another cited the number of pages and identification problems associated with attaching copies of the contract escalator terms for each contract reported. However, several commentors, notably several public utilities, all recommended that the reporting party be required to submit a copy of the complete gas sales contract, notwithstanding their voluminous nature.

In reporting price escalator terms, respondents, at their option, may provide either a copy of the escalator terms in a contract or a brief summary of the provisions and effective dates. The format used on FERC Form 45 shall be deemed acceptable for providing summaries. We have also simplified the requirements for identifying copies of escalator provisions that are submitted in lieu of summaries. We believe a copy or summary of pricing provisions will be adequate for compliance purposes and reject the suggestion to require a copy of the complete contract.

E. REPORT PERIOD AND FILING DATE

Most comments stated that additional time would be required to file reports under Part 276. They suggest that this is due to the time required to obtain and allocate volume figures. Several requested that the reporting period be changed to a calendar year basis. One company commented that where volume information is not available on a calendar month basis, pipelines should be permitted to report volumes for the billing period most closely corresponding to the calendar month.

We agree that the filing date in the Interim Regulations does not allow sufficient time to prepare a report for a reporting period ending on January 31. To allow sufficient time to report, and to be consistent with previous FERC and industry practice, we have changed the reporting period to a calendar year basis with reports to be filed annually by April 1 following the end of the period. In view of the short time remaining before initial reports are due, as required by Commission order issued on February 2, 1979 in Docket No. RM79-3, we have amended Part 276 to provide for a June 1, 1979 deadline. The initial report shall include data for only one month—December 1978. Where the billing period does not correspond to a calendar month, the sales volume reported should be the volume delivered during the billing period most closely corresponding to the calendar month.

F. RECORDKEEPING REQUIREMENTS

Because of the inclusion of new § 276.106, we have redesignated previous § 276.106 as § 276.107 and § 276.107 as § 276.108. Several comments suggested that the record retention period of three years following contract expiration imposed by § 276.108 on sellers is unrealistically long and should be based on the actual transaction or event to which the books and records relate.

We agree that, except with respect to the contract itself, the record retention period prescribed in § 276.108 is too long. However, we cannot agree that a three year record retention period referenced to a transaction or event is sufficient for purposes of compliance. We therefore find that the general record retention requirement of § 276.108 should be referenced to the date of the reports. In all cases, however, the contract itself must be retained three years after expiration. Accordingly, we have amended §§ 276.102(a)(2)(ii), 276.102(e)(2), 276.103(a)(2)(ii), 276.103(e)(2), 276.105(a)(2), and 276.108 and the associated oath statements to reflect this change.

One pipeline company has requested that instrument charts not be considered "books and records" for purposes of § 276.108. We shall reject this suggestion. Instrument charts are the only viable means of verifying sales volumes. We also believe that a three year retention obligation is not unduly burdensome.

G. SUPPORTING STATEMENT FOR SALES UNDER SECTION 109

In the Interim Regulations, § 276.104(d)(2) requires a statement identifying the well, reservoir, and acreage from which natural gas qualifying under Section 109 is produced. The statement is only required, however, if the natural gas was not committed or dedicated to interstate commerce on November 8, 1978. We believe that the importance of well and reservoir identification for sales under Section 109 is not a function of the commitment status of the natural gas and therefore find good cause to delete the condition "if the natural gas was not committed or dedicated to interstate commerce on November 8, 1978" from § 276.104(d)(2) and to redesignate that section as § 276.104(e). It is not anticipated that this change will increase the burden on respondents.

IV. PUBLIC PROCEDURES AND EFFECTIVE DATE

The regulations in Part 276 were originally proposed for comment in November of 1978 and issued as interim regulations on December 1, 1978 (43 FR 56448 (Dec. 1, 1978)). For 60 days thereafter comments were received and during that period public hearings were held on these regulations. By this process the Commission complied with the provisions of section 502(b) of the NGPA which requires that "[t]o the maximum extent practicable," an opportunity for the oral presentation of data, views, and arguments be afforded for certain regulations under the NGPA.

The amendments to Part 276 contained in this order and the attendant forms, instructions, and affidavits for Subpart A of Part 276 rest upon considerations given to the information received during the above described notice, comment, and hearing process. In addition, Part 276, as amended on February 2, 1979, requires the filing of information on or before May 1, 1979. The amendments set forth below reduce some of the reporting burdens contained in the Interim Regulations. The amendments, including the forms to be used in making the required filings must be promulgated now in order to give to those persons subject to the regulations adequate time for the preparation and filing of the forms. Accordingly, the Commission finds that further notice and public procedure on these rules is unnecessary and impractical and that good cause exists to dispense with additional notice and procedure, and to make Part 276 as amended, effective immediately as final regulations.

(Natural Gas Act, as amended, 15 U.S.C. 717, *et seq.*; Energy Supply and Environmental Coordination Act, 15 U.S.C. 791, *et seq.*; Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350; Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267)

In consideration of the foregoing, FERC Forms 122, 123, and 124 and accompanying affidavits and instructions as set forth below as Appendix A are hereby promulgated effective immediately, and Part 276 of Subchapter H, Chapter I, Title 18, Code of Federal Regulations, as issued as interim regulations (43 FR 56448 (Dec. 1, 1978)), and amended by order of the Commission dated February 2, 1979, are promulgated as final regulations and amended as set forth below, effective immediately.

By the Commission.

KENNETH F. PLUMB,
Secretary.

[¶ 30,043]

44 F. R. 20077 (April 4, 1979).

[Docket No. RM78-19]

AMENDMENT TO RULES RELATING TO DELEGATION OF COMMISSION'S AUTHORITY

AGENCY: Federal Energy Regulatory Commission

ACTION: Final Rule

SUMMARY: This rule amends § 3.5(f) of the Federal Energy Regulatory Commission's regulations. By this amendment to its rules, the Commission is delegating to the Director of the Office of Pipeline and Producer Regulation the authority, under § 275.202 (b)(2) of its regulations to notify jurisdictional agencies when their notices of determination are incomplete.

EFFECTIVE DATE: March 19, 1979
1979

FOR FURTHER INFORMATION CONTACT:

Eli Farrah
Federal Energy Regulatory Commission
825 North Capitol Street, N. E.
Washington, D. C. 20426

Section 501(a) of the Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350 (NGPA), provides that "the Commission — is authorized to perform any and all acts —, and to prescribe, issue, amend, and rescind such rules and orders as it may find necessary or appropriate to carry out its functions under this Act." Pursuant to this authority, the Commission is amending § 3.5(f) of its rules by adding subparagraph (9) which delegates authority to the Director of the Office of Pipeline and Producer Regulation (OPPR) to act in behalf of the Commission in carrying out its authority under 18 C. F. R., § 275.202(b)(2).

Background

Section 275.202(a) of the Commission's rules states that except as provided in paragraph (b) of this section, a determination submitted to the Commission by a jurisdictional agency shall become final 45 days after the date on which the Commission received notice of the determination, unless within the 45-day period the Commission makes certain preliminary findings and issues written notice of such preliminary findings, including the reasons for those findings. Section 275.202(b) provides that notwithstanding the provisions of paragraph (a), the 45-day period for Commission review of a determination shall not begin if the notice forwarded to the Commission by the jurisdictional agency does not contain all the information required in § 274.104(a)(4) and (5), and the Commission notifies the jurisdictional agency, within 45 days after the date on which the Commission receives notice of the determination, that the notice is incomplete. Therefore, when the Commission receives an incomplete notice of a determination by a jurisdictional agency, it is not only unable to perform its review function as prescribed by section 503(b) of the NGPA, but it also must notify the jurisdictional agency, within 45 days, that the notice is incomplete or the jurisdictional agency's determination becomes final and review is foreclosed. It is, therefore, essential that the ministerial act of notification be accomplished expeditiously.

By this amendment to its rules, the Commission is delegating to the Director of OPPR the authority, under § 275.202(b)(2) of its regulations, to notify jurisdictional agencies when their notices of determination are incomplete. This will not only enable the Commission to focus on more complex and controversial tasks, but it will also ensure that the Commission's review function under section 503(b) of the NGPA will be carried out expeditiously.

Under § 1.7(d) of the Commission's Rules, any action taken pursuant to authority delegated by the Commission may be appealed to the Commission by filing a petition within 15 days after such action.

Effective Date

The amendment prescribed herein concerns matters of agency organization and procedure which do not require notice or hearing under 5 U. S. C. § 553. For the reasons set forth above, the Commission finds that it is appropriate and in the public interest to adopt the amendment hereinafter set forth effective upon the issuance of this order. (Administrative Procedure Act, 5 U. S. C. 551, Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350), Department of Energy Organization Act (Pub. L. 95-91), (E. O. 12009, 42 F. R. 46267)

In consideration of the foregoing, the Commission proposes to amend Chapter I of Title 18, Code of Federal Regulations, as set forth below.

[¶ 30,044]

44 F. R. 18961 (March 30, 1979).

[Docket No. RM79-32; Order No. 24]

PART 1—RULES OF PRACTICE AND PROCEDURE

Procedures for Adjustments of Rules and Orders Issued by the Federal Energy Regulatory Commission Under the NGPA

Federal Energy Regulatory Commission

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The purpose of this rule is to provide, on an interim basis, procedures whereby any person may seek an adjustment from the Commission rules and orders, having the effect of rules, which are issued under the Natural Gas Policy Act of 1978. This section also makes certaih existing Commission procedures applicable to review of adjustment decisions. Adjustment relief may be granted in the form of an exception, exemption, modification or rescission to a rule or order upon a showing by applicant that relief is necessary to prevent special hardship, inequity or unfair distribution of burdens.

EFFECTIVE DATE: March 22, 1979.

FOR FURTHER INFORMATION CONTACT:

Mary Jane Reynolds (Office of General Counsel), Energy Regulatory Commission, 825 N. Capitol St. NE., Room 8000, Washington, D.C. 20426, (202) 275-4283.

In the matter of procedures for adjustments of rules and orders issued by the Federal Energy Regulatory Commission under the NGPA. Interim regulation issued March 22, 1979.

BACKGROUND

The Natural Gas Policy Act (NGPA) mandates a new legislative framework for many facets of the natural gas industry. The law affects sales, transmission and distribution of natural gas. A primary effect of the new statute is to replace case-by-case adjudication of these various aspects of the Natural Gas Act with general rules applicable to the entire industry. Section 502(c) requires the Federal Energy Regulatory Commission (Commission) to provide procedures for obtaining adjustments to these rules and orders implementing the NGPA. Section 502(c) requires the Commission to adopt procedural rules under which any person may seek an "adjustment"—exception, exemption, modification or rescis-

sion*—of rules and orders, which have the applicability and effect of rules, and which are issued under the NGPA. Adjustments are to be granted to prevent special hardship, inequity or unfair distribution of burdens. Section 502(c) also requires procedures whereby any person aggrieved or adversely affected by the denial of a request for adjustment may seek the Commission review. The rules promulgated must establish procedures which include "an opportunity for oral presentation of data, views, and arguments."

It is difficult for the Commission to predict, at this time, the number of adjustments which may be requested. It is equally difficult to determine, in the absence of any experience under this new statute, the scope and nature of the effect that an adjustment may have. The proposed regulation establishes an abbreviated "paper pleading" procedure by which the problems can be presented to and resolved by the Commission Staff. Staff will have authority to deny requests for adjustment. However, where Staff proposes to grant relief, in whole or in part, the Commission will have 30 days from the date of the Staff determination to set the matter for Commission review.

The interim regulation promulgated herein provides for administrative review of *all* initial adjustment decisions. The Commission is required by section 502(c) to review denials of adjustment requests and is exercising its discretionary authority to review grants of adjustment. Section 502(c) clearly requires the Commission to establish procedures for review of denials of requests for adjustments. "If any person is aggrieved or adversely affected by the denial of a request for adjustment under the preceding sentence, such person may request review of such denial . . ." We note that our regulations implementing our authority under section 504(b) of the Department of Energy Organization Act, 42 U.S.C. 7194(b) (DOE Act), which contains similar review language to that used here, provide for the Commission to review only denials by the Secretary of Energy (Secretary) of adjustment requests. The Commission's jurisdiction to review adjustments under section 504(b) of the DOE Act concerns specific appellate review of decisions of another agency. The Commission has no statutory authority to expand its review jurisdiction under the DOE Act to include decisions by the Secretary which grant adjustments.

However, the Commission's authority under the NGPA is broader. Section 502(c) gives the Commission original jurisdiction to grant adjustments from its own rules and orders under the NGPA. This necessarily includes authority to provide internal procedures for the effective exercise of this jurisdiction. Specifically, section 501(a) of the NGPA authorizes the Commission to prescribe rules ". . . as it may find necessary or appropriate to carry out its functions under [the NGPA]." Therefore, unlike its authority under the DOE Act, the Commission's authority under the NGPA extends to review of both grants and denials of adjustments.

The Commission is exercising its authority to review grants of adjustments under the NGPA because it recognizes that the impact of adjustment relief could be very broad, in view of the complexity of the new regulatory scheme and in view of the fact that many persons not previously subject to Commission jurisdiction under the Natural Gas Act will be directly or indirectly affected by Commission action under the NGPA. At least until there is more experience with the impact of the NGPA, the Commission believes it may be beneficial to undertake the review of grants of adjustments, in spite of the administrative burden that such review will impose upon Commission resources. Accordingly, the Commission finds it necessary and appropriate to review, on an interim basis, grants of adjustments under the NGPA.

In sum, to carry out our original responsibilities under section 502(c), we are providing that initial decisions by

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*Section 502(c) also requires procedures for seeking interpretations of Commission rules and orders.

Staff are, on application of a person aggrieved by a denial of an adjustment application, subject to review by the Commission. The Commission is exercising its discretionary authority under section 501 to permit a person aggrieved by a grant of an adjustment application to obtain Commission review of the grant. (As discussed below, persons who may seek Commission review must have participated, or have sought and been denied an opportunity to participate, in the initial proceeding.) In addition, the rule permits the Commission, in its discretion, to review a grant of an adjustment application even if it is uncontested.

Any person who participates in the review proceeding may request a hearing on review. Although the Commission has not determined that the statute grants intervenors the right to a hearing, the review procedures provide that right. The Commission believes, consistent with the previous discussion concerning review of grants of adjustments and the abbreviated nature of the paper pleading procedure for initial decisions on adjustments, that for the present time, providing intervenors with the right to request a hearing will further enhance the ability of all persons involved in the proceeding to fully develop the record for decision-making purposes.

SUMMARY OF THE REGULATION

The new procedures for adjustments under the NGPA are set forth in a new § 1.41. Paragraph (a) makes clear that the procedures apply to adjustments from rules as well as from orders having the effect of rules. The procedures do not apply to orders issued under sections 301, 302 or 303 of the NGPA and do not apply to determinations of just and reasonable rates as provided for in sections 104, 106 and 109 of the NGPA. Certain of the existing Commission procedural regulations apply to adjustment proceedings. Therefore, paragraph (a)(2)(i) provides that the existing Commission regulations concerning the form of pleadings, dates for filing, service requirements and other similar provisions apply to these adjustment regulations. Since a proceeding under the interim rule is to be conducted almost exclusively by Staff, all references to "Commission" in the existing rules made applicable to this rule under paragraph (a)(2)(i), except § 1.14, mean "Staff" for purposes of this rule.

An adjustment proceeding is, generally, exclusively a paper proceeding. Staff does not participate in the proceeding as a party. Staff's only role is that of decision maker. For purposes of the initial application for adjustment "Staff" means the Director of the Office of Pipeline and Producer Regulation (OPPR) or his designate. See paragraph (b)(7). Therefore, it is anticipated that the initial applications for adjustment will be processed and decided by OPPR. However, if it is determined that an adjustment should be granted, the Commission has 30 days to initiate Commission review of Staff's order.

Paragraph (c) provides that an adjustment proceeding is commenced by filing an application for adjustment. Any person who believes he or she will experience special hardship, inequity or unfair distribution of burdens because of an NGPA rule or order issued by the Commission may file a request for adjustment.

Paragraph (d) sets forth the requirements for content and service of the initial application. The application must contain: (1) a complete statement of all relevant facts, including all documentary support pertaining to the circumstances, act or transaction that is the subject of the application; (2) a statement of the business reasons why the relief should be granted and the business consequences that will result if the relief is denied; and (3) a statement specifying how the denial of relief will cause the applicant to suffer special hardship, inequity or unfair distribution of burdens. The application must also set forth the legal basis for the relief and the precise nature of the relief sought. The applicant must serve a copy of the application (or a copy with confidential information deleted) on each person whom the applicant can reasonably ascertain will sustain a direct and measurable economic impact if the adjustment relief is granted. The applicant must file with its application a certificate of service indicating the names and addresses of all persons served. Staff may require the applicant to make additional service. The application must also contain a short summary of the relief requested which will be published in the FEDERAL REGISTER.

Paragraph (e) establishes the rules for intervention. The mere fact that a person has been served with the application will not automatically make such person a party to the proceeding. Rather, all persons who wish to participate in the proceeding must file a petition to intervene. The standards for intervention are those set forth in § 1.8 of the Commission's Rules of Practice and Procedure.

Once Staff has granted a petition to intervene, the intervenor has 15 days to file a response to the application. The applicant is entitled to file a rebuttal within 15 days of service of the filing by the intervenor.

Generally, these filings—the initial application, the intervenor's response and the applicant's rebuttal—will comprise the record which Staff evaluates under paragraph (g) to decide a request for adjustment. Staff may obtain additional information if the applicant files amended pleadings (paragraph (f)) or if Staff requests additional information or conducts an investigation as permitted under paragraph (g)(2).

Paragraph (h) codifies the statutory criteria for granting adjustment relief: special hardship, inequity and unfair distribution of burdens. The applicant has the burden of establishing the need for relief and should the applicant fail to submit sufficient evidence, Staff may dismiss the application without prejudice. If so, the applicant may refile for the same relief at a later date. However, if Staff has requested additional material information and the applicant has failed to supply the information, the application may be denied.

The provisions concerning the order deciding the initial application for adjustment are found in paragraph (i). As stated previously, Staff makes the initial decision on adjustments. It is reduced to a written order, articulating the basis for the decision and noting any dispute with the factual assertions of the applicant. If Staff fails to issue an order rendering a decision on an application for adjustment within 150 days of the filing of the application, applicant may treat the application as having been denied. Within 30 days thereafter, it may request review by the Commission in accordance with paragraph (j)(1). An order issued by Staff which grants an adjustment is effective 30 days after it is issued unless: (1) a petition for review is filed in accordance with paragraph (j)(1); or (2) the Commission directs that the order be reviewed in accordance with paragraph (j)(2).

Any person may seek administrative review of the initial decision granting or denying a request for adjustment, if: (1) that person is aggrieved or adversely affected by that decision; and, (2) if that person participated, or sought and was denied the opportunity to participate, in the proceeding under this section. In order to seek judicial review, the administrative appeal must first be taken in accordance with paragraph (j). Under the rule adopted today, the Commission is adapting its existing rules concerning review of denials of adjustments of the Secretary, codified at 18 CFR § 1.40, to apply to requests by aggrieved parties for review of initial adjustment decisions under the NGPA. Thus, for purposes of NGPA adjustments, the provisions of 18 CFR § 1.40, as modified in paragraph (j), apply both to denials and grants of adjustment relief. Staff takes the role of the Secretary with respect to review in § 1.40. Hence, Staff will file the record for the review at the Commission level. In § 1.40, however, the Secretary is an adverse party in all proceedings reviewing denials of adjustments by the Secretary. In contradistinction, Staff has discretion to participate as an adversary in any review of a denial of an NGPA adjustment. Staff may not participate in the proceeding as an adverse party with respect to the review of a grant of adjustment. If the Commission orders the review of a Staff order granting relief under paragraph (i)(3)(iii), but no party petitions for review, the procedure will conform as far as practicable with proceedings under § 1.40. The order directing review shall further specify the manner in which the proceeding is conducted.

As a general proposition, there are no hearings and no discovery in initial adjustment proceedings held by Staff. However, Staff may direct the conference be convened in accordance with the provisions of paragraph (k). In addition, any party to any adjustment proceeding may file a motion requesting an additional procedure or procedural ruling. See paragraph (n). Staff has authority to provide additional procedures and to make rulings on requests for procedural rulings. See paragraph (o).

The Commission recognizes that certain applications for adjustment relief will contain confidential information. The Commission regulations allow a person whose application contains confidential information to request confidential treatment of such information. The procedures for doing so are set forth in paragraph (l). Any party to the proceeding who wishes to obtain information supplied on the basis of confidentiality may make a request for such information under the Freedom of Information Act.

Paragraph (m) allows the applicant to make a request for interim relief—a stay—pending resolution of the application for adjustment on its merits. Staff may issue interim relief but the Commission may, at any time, on its own motion, revoke, modify, rescind or stay the interim order. It may take any other appropriate action concerning the order granting interim relief. Paragraph (m)(2)(D)(ii).

Paragraph (p) makes clear that all actions taken under this section concerning adjustments are made by Staff and that no appeals may be taken from Staff decisions except for review of grants and denials of adjustments in accordance with paragraph (j). However, as previously discussed, the Commission may, on its own motion, modify, revoke, rescind, stay or otherwise act upon any interim relief issued by Staff. The Commission may also, on its own motion, review any order of Staff granting adjustment relief.

Paragraph (q) is intended to assure that those members of the Staff who make the initial decision for adjustment relief and those who act as counsel or a witness to the review of an adjustment by the Commission shall not advise the Commission in the decision on review under paragraph (j).

EFFECTIVE DATE

These regulations are being issued effective immediately on an interim basis, because the Commission finds that the need to have regulations in place, implementing section 502(c) of the NGPA to apply to any requests for adjustments prior to the issuance of final rules, constitutes good cause to find prior notice and public procedure to be impracticable and to waive publication not less than 30 days prior to the effective date. The Commission requests data, views or arguments with respect to these regulations and will also hold a public hearing. After evaluating the information received, the Commission will make any appropriate revisions to these regulations.

WRITTEN COMMENT PROCEDURES

Interested persons are invited to submit written comments, data, views or arguments with respect to this proposal. An original and 14 copies should be filed with the Secretary of the Commission. All comments received prior to May 22, 1979 will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, 825 North Capitol Street, N.E., Washington, D.C., during regular business hours. Comments should be submitted to the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should reference Docket No. RM79-32.

PUBLIC HEARING PROCEDURES

A public hearing concerning this proposal will be held in Washington, D.C. on May 1, 1979, beginning at 9:30 a.m. and will continue if necessary on the following day. Any person interested in this proceeding or representing a group or class of persons interested in this proceeding may make a presentation at the hearing provided a written request to participate is received by the Secretary of the Commission prior to 4:30 p.m., on April 16, 1979.

Requests to participate in the hearing should include a reference to Docket No. RM79-32, as well as a concise summary of the proposed oral presentation and a number where the person making the request may be reached by telephone. Prior to the hearing, each person filing a request to participate will be contacted by the presiding officer or his designee for scheduling purposes. At least five copies of the statement shall be submitted to the Secretary of the Commission prior to 4:00 p.m., on April 27, 1979. The presiding officer is authorized to limit oral presentation at the public hearing both as to length and as to substance. Persons participating in the public hearing should, if possible, bring 10 copies of their testimony to the hearing.

The hearing will not be a judicial or evidentiary-type hearing. There will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested person may submit questions to the presiding officer to be asked of persons making statements. The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. If time permits, at the conclusion of the initial oral statements, persons who have made oral statements will be given the opportunity to make a rebuttal statement. Any further procedural rules will be announced by the presiding officer at the hearing. A transcript of the hearing will be made available at the Commission's Office of Public Information.

(Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350; Department of Energy Organization Act, Pub. L. 95-91, 91 Stat. 565 *et seq.*, E.O. 12009, 42 FR 46267; Natural Gas Act, *as amended*, 15 U.S.C. §§ 717 *et seq.*)

In consideration of the foregoing, Part I, Subchapter A, Chapter I of Title 18, Code of Federal Regulations, is amended as set forth below, effective immediately.

By the Commission.

KENNETH F. PLUMB,
Secretary.

[¶ 30,045]

44 F. R. 18966 (March 30, 1979).

[Docket No. RM79-26]

PART 270—RULES GENERALLY APPLICABLE TO REGULATED SALES OF NATURAL GAS

Interpretive Rule; Commission Interpretation of Section 314 of the NGPA

AGENCY: Federal Energy Regulatory Commission.

ACTION: Interpretive Rule, amending existing rules.

SUMMARY: The Federal Energy Regulatory Commission interprets the definition of "natural gas covered by this Act" in Section 314(b) of the Natural Gas Policy Act of 1978 (NGPA), Pub. L. 95-621, to include any natural gas which falls within one or more of the categories listed in the definition. The rule clarifies the status of commingling or related contract clauses in the context of sales or assignments by intrastate pipelines or declared natural gas supply emergencies.

EFFECTIVE DATE: March 9, 1979.

FOR FURTHER INFORMATION CONTACT:

Robert C. Platt, Office of the General Counsel, Federal Energy Regulatory Commmission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 275-0161.

SUPPLEMENTARY INFORMATION:

INTRODUCTION

One of the primary purposes of the Natural Gas Policy Act of 1978, Pub. L. 95-621 (NGPA) was to eliminate the distinction between the regulatory consequences of making sales in the interstate and the intrastate natural gas markets. Section 314 of the NGPA is an important part of the statutory scheme to remove these distinctions.

Section 314(a) declares as unenforceable certain sales contract provisions which: (a) Prohibit the commingling of the natural gas sold under the contract with natural gas subject to the Commission's Natural Gas Act (NGA) jurisdiction; (b) prohibit later sales in the interstate market of the natural gas sold under the contract; (c) prohibit transportation of the natural gas sold under the contract by a natural-gas company; or, (d) terminate or grant the option to terminate the contract upon such commingling, sale or transportation.

The provisions of section 314 apply only to "natural gas covered by this Act." Section 314(b) defines this term:

> [T]he term "natural gas covered by this Act" means—
>
> (1) natural gas which is not committed or dedicated to interstate commerce as of the day before the date of the enactment of this Act;
>
> (2) natural gas, the sale in interstate commerce of which—
>
> (A) is authorized under section 302(a) or 311(b); or
>
> (B) is pursuant to an assignment under section 312(a); and
>
> (3) natural gas, the transportation in interstate commerce of which is—
>
> (A) pursuant to any order under section 302(c) or section 303(b), (c), (d) or (h); or
>
> (B) authorized by the Commission under section 311(a).

A question of statutory construction arises as to the application of section 314. The question raised is whether the provisions of section 314(a) making commingling clauses unenforceable, apply only to natural gas which is described in all three clauses in section 314(b) or whether the section 314(a) prohibitions apply to natural gas which falls within any one of the section 314(b) clauses.

Because both interpretations have been ascribed to section 314(b), the Commission believes an interpretive rule will remove uncertainty surrounding the meaning of the section. The proposed interpretation would clarify the definition by stating that the definition should be read disjunctively. This reading would make section 314 applicable to natural gas which is in one or more of the three categories listed in section 314(b) rather than limiting its applicability to natural gas which meets all three tests.

LEGAL ANALYSIS

A disjunctive reading of the section 314(b) definition is supported by both a textual analysis and the legislative history.[1] Four arguments support a disjunctive reading of the definition.

First, the draftsmen of the NGPA adopted a disjunctive usage in many of the NGPA definitions. Under this usage, definitional lists which are immediately preceded by the word "means" and joined by the word "and" are to be read disjunctively. For example, the section 2(18) definition of "committed or dedicated to interstate commerce" includes two categories of natural gas.[2] As in section 314(b), the NGPA draftsmen deliberately started each category by repeating "natural gas". Although the two categories are joined by the word "and", a disjunctive reading is surely intended in this instance. One category describes OCS gas and the other describes a jurisdictional test. A conjunctive reading would limit the definition to OCS gas which also meets the jurisdictional test. However, other provisions of the NGPA contemplate onshore "committed or dedicated" gas as well as "committed or dedicated" OCS gas. Similarly, the definition of "production day" in section 108 uses the word "and" to join "any day during which natural gas is produced" with "any day during which natural gas is not produced. . . ." In like manner, this same disjunctive usage is in the section 314(b) definitions.

Second, a conjunctive reading would be implausibly narrow. For example, if the section 314(b)(1), (b)(2)(A) and (b)(3)(B) tests must all be met in order to be included within the definition of "natural gas covered by this Act", then the Section 314(a) limitations would apply to natural gas which is not committed or dedicated to interstate commerce and sold by an intrastate pipeline under section 311(b) only if it happened to be subsequently transported under section 311(a). Congress did not intend this result. Sections 311 and 312 represent a statutory mandate to create an integrated nationwide system for the sale and transportation of natural gas. This broad mandate was not intended to be confined to the transportation of gas which happens to have been sold under section 311(b). Since the statutory authority for each of these transactions contained in the NGPA is designed to address discrete issues which have arisen under NGA regulation, Congress could not have intended a conjunctive reading of section 314.

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[1] Even if a syntatic analysis did not support the disjunctive reading, the courts have permitted wide latitude in ascribing a disjunctive meaning to the word "and":

> In the construction of statutes, it is the duty of the Court to ascertain the clear intention of the legislature. In order to do this, Courts are often compelled to construe 'or' as meaning 'and', and again 'and' as meaning 'or'.

United States v. *Fisk*, 3 Wall. 445, 448, 70 U.S. 445, 448 (1866), *accord*, *Peacock* v. *Lubbock Compress Co.*, 252 F.2d 892 (5 Cir. 1958), *cert. denied* 356 U.S. 973 (1958).

[2] Section 2(18)(A) states "—The term 'committed or dedicated to interstate commerce', when used with respect to natural gas, means—

> (i) natural gas which is from the Outer Continental Shelf; and
>
> (ii) natural gas which, if sold, would be required to be sold in interstate commerce (within the meaning of the Natural Gas Act) under the Natural Gas Act, or any provision of such Act."

Similarly, the legislative intent would not permit private contractual prohibitions to frustrate the emergency powers accorded to the President during a declared natural gas supply emergency. Yet, a conjunctive reading of section 314(b)(3)(A) with sections 314(b)(1) and (2) would allow commonplace commingling clauses to immunize natural gas from the President's emergency powers to redirect the gas into the interstate market. The President's emergency powers were not so circumscribed under the Emergency Natural Gas Act of 1977, Pub. L. 95-2 (ENGA), section 9(b), and the legislative history of the NGPA fails to support such a substantial change from its predecessor statute, the ENGA.

Third, the legislative history of the NGPA supports a disjunctive reading. The Statement of Managers indicates that section 314 reflects the House version of the bill (H. Report No. 95-1752, 95th Cong. 2d Sess. at 110 (1978)). Section 414(c) of the House version (H.R. 8444, passed on August 5, 1977) corresponds to NGPA Section 314. The prohibition against commingling in the House version applied to "the first sale of any natural gas to which the provisions of sections 404, 406, 407, 409, or 413(e)(4) apply."

These sections roughly correspond to the three categories listed in the NGPA section 314(b), definition of "natural gas covered by this Act." Because these sections are listed disjunctively in both the text of H.R. 8444 and its corresponding committee report (H.R. Rept. No. 543, Vol. 2, 95th Cong., 1st Sess. at 405 (1977)), a disjunctive reading should be incorporated by reference into the Statement of Managers of the final version of the NGPA.

Finally, consideration of the history and purpose of commingling clauses would demonstrate that a disjunctive reading would fulfill the Congressional intent to obviate the effect of clauses entered into during the former era of NGA regulation as opposed to the present era of NGPA regulation. The Commission had found in a series of cases under the NGA that if a sale was made in interstate commerce, the production was subject to not only the pricing policies of the Commission but also the abandonment provisions of NGA section 7(b). Similarly, the Commission had held that transportation of gas by interstate facilities could render the producers of such gas jurisdictional. Consequently, in order to avoid potential regulation under the NGA as a result of either sales or transportation in interstate commerce, producers began to include clauses prohibiting commingling. Since the NGPA's enactment, natural gas which was not "committed or dedicated to the interstate market" as of November 8, 1978 cannot become so "committed or dedicated" by either sales or transportation of natural gas in interstate commerce. Therefore, the need for such clauses in any contract has disappeared. The public policy goals of the NGPA do, then, require the broad reading of section 314 embodied in this interpretive rule.

For these reasons, the Commission concludes that § 314(b) must be read disjunctively, and accordingly issues an interpretive rule which embodies this conclusion.

(Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, Department of Energy Organization Act, Pub. L. 95-91, Administrative Procedure Act, 5 U.S.C. § 553, E.O. 12009, 42 FR 46267.)

This order merely clarifies NGPA section 314. Because this is an interpretive rule, the Commission finds that it may become effective immediately and that no provision to give interested persons an opportunity to participate in the rule making is necessary. 5 U.S.C. § 553.

In consideration of the foregoing, the Commission amends Part 270 of Title 18 of the Code of Federal Regulations as set forth below.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,046]

44 F. R. 19387 (April 3, 1979).

18 CFR Parts 154 and 157

Natural Gas Policy Act; Amendments to the Commission's Regulations Relating to Independent Producer Filing Requirements

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Commission is amending filing requirements relating to certain natural gas sold under the pricing provisions of the Natural Gas Policy Act of 1978. In order to avoid unduly burdensome monthly rate change filings by producers, the procedure allowing a one-time blanket affidavit filing has been expanded to include gas finally determined to qualify as certain Outer Continental Shelf gas and stripper well gas. Because a producer cannot know precisely in advance when a final determination will be made relating to these two categories of gas, the regulations are amended to allow a rate change filing to establish the applicable base rate to take effect on the later of the date of final determination or of initial deliveries, if filed within thirty days of final determination.

EFFECTIVE DATE: March 27, 1979.

FOR FURTHER INFORMATION CONTACT:
Mark G. Magnuson, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 275-4850.

Howard Kilchrist, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 275-4539.

SUPPLEMENTARY INFORMATION:

Order No. 25

(Issued March 27, 1979.)

Before Commissioners: Charles B. Curtis, Chairman; Don S. Smith, Georgiana Sheldon, and George R. Hall.

Amendments to the Commission's Regulations Relating to Independent Producer Filing Requirements; Docket No. RM79-31.

The Federal Energy Regulatory Commission (Commission) gives notice that it hereby amends §§ 154.94 and 157.40 concerning filing requirements relating to certain natural gas sold pursuant to the pricing provisions of the Natural Gas Policy Act of 1978 (NGPA).

I. *Background*

On November 17, 1978, and December 28, 1978, the Commission issued Order Nos. 15 and 15-A in this docket which amended Parts 154 and 157 of its regulation relating to producer filing requirements. The amended regulations require a producer to file a blanket affidavit with the Commission in order to charge and collect a maximum lawful price including periodic escalations under sections 104 and 106(a) of the NGPA. Since sections 104 and 106(a) of the NGPA cover gas which was committed or dedicated to the interstate market as of November 8, 1978, the rate change filing requirements of the Natural Gas Act continue to apply to such gas even though the price therefore is determined in accordance with the provisions of the NGPA. The amendments adopted in Order Nos. 15 and 15-A provide for a one-time blanket affidavit filing by a producer selling section 104 or 106(a) gas. They were necessary to avoid the unduly burdensome monthly rate change filings which would have been required under the old regulations. Without the amendments, section 104 and 106(a) producers would have been required to file a rate change every time they intended to charge and collect the additional increment in the NGPA maximum lawful price reflecting the monthly inflation adjustment.

In Order No. 15 the Commission also recognized the fact that the rate change filing requirements of the Natural Gas Act would continue to apply to natural gas which was committed or dedicated to the interstate market as of November 8, 1978 and which is subject to the interim collection provisions of section 503(e) of the NGPA. The Commission determined that the filing requirements imposed by that section would satisfy the filing and notice requirements of the Natural Gas Act.[1]

One problem remains to be addressed. This concerns the filing requirements for natural gas which was committed or dedicated to the interstate market as of November 8, 1978 and for which a jurisdictional agency's determination of eligibility has become final. The categories of natural gas for which a determination of eligibility is made by a jurisdictional agency are new natural gas (as defined in section 102(c) of the NGPA), certain OCS gas (section 102(d)), gas from new onshore production wells (section 103), high cost natural gas (section 107) and stripper well natural gas (section 108). Until a final determination of eligibility has been made regarding each of these categories of gas, the prices therefore are charged in accordance with the interim collection procedures of section 503(e), which, as noted above, have been deemed to satisfy the filing and notice requirements of the Natural Gas Act.

Furthermore, once a final determination has been made that natural gas qualifies as new natural gas, high-cost natural gas or gas from new onshore production wells, the sale of such natural gas is no longer subject to the Commission's jurisdiction as provided in section 601(a)(1)(B) of the NGPA. Accordingly, the filing and notice requirements of the Natural Gas Act would not apply to these categories of natural gas after a final determination of eligibility has been made, but such requirements would continue to apply to certain OCS gas (section 102(d)) and stripper well natural gas (section 108).

Since both the sections 102(d) and 108 gas categories receive the monthly inflation adjustment, it is necessary to provide a blanket affidavit procedure covering these categories of gas in order to avoid the necessity of monthly rate change filings, a requirement that the Commission has already determined to be inappropriate in the case of sections 104 and 106(a) gas. The amendments adopted herein would revise our current blanket affidavit procedure set forth in § 154.94(h) in order to expand the blanket affidavit coverage to include natural gas which has been finally determined to be section 102(d) or 108 gas.

Under the procedure implemented by Order Nos. 15 and 15–A, the blanket affidavit filings covered the maximum lawful prices established in sections 104(b)(1)(A) or 106(a) to which the producer was entitled on the basis of having qualified under the Natural Gas Act for a base rate. We shall expand the definition of base rate to include a rate applicable to natural gas which has been finally determined to be eligible under sections 102(d) or 108 of the NGPA. However, we shall provide that a rate change filing to establish a section 102(d) or 108 base rate may take effect on the date of final determination or date of initial deliveries, whichever is later, if filed within thirty days of the date of final determination. This amendment is necessary because a producer cannot know with precision ahead of time a particular date of final determination. In cases where a producer does not make the requisite rate change filing within thirty days of the date of final determination, he would be subject to the rule originally promulgated in Order No. 15 at § 154.94(h)(2)(iii) that the rate change filing takes effect on the thirty-first day after date of filing (or any later effective date specified in the filing), unless such filing has been suspended or rejected.

We have also revised the form of the blanket affidavit and the instructions therefor in Appendix A and Exhibit A to § 154.94 to include reference to the collection of the sections 102(d) and 108 maximum lawful prices. Producers receiving their initial section 102(d) or 108 final determinations will be required to file this amended form of the blanket affidavit in order to cover such sales under the blanket affidavit. We shall provide that such amended blanket affidavit filed concurrently with the rate change filing to collect the section 102(d) or 108 base rate shall become effective on the date the rate change filing becomes effective. However, we note that under § 154.94(h)(3)(ii) further affidavit filings would not be necessary if future filings to establish the section 102(d) or 108 base rate state that such first sales would be covered by the previously filed amended affidavit.

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[1] *See* § 154.94(i) of the Commission's Regulations.

Also, we find it necessary to revise our protest procedure set forth in § 154.94(h)(8). This procedure currently calls for a protest to be filed only in response to the filing of a blanket affidavit. However, in the case of sections 102(d) and 108 gas, a rate change filing to establish the base rate must be filed once under each rate schedule when a producer receives a final determination of eligibility applicable to the first well or wells under such rate schedule which qualify for the section 102(d) or 108 base rate. This procedure will be used to establish the contractual authority to charge the 102(d) and 108 rates as well as to satisfy the notice requirements of the Natural Gas Act. We shall amend § 154.94(h)(8) in order to provide an opportunity for parties to protest each rate change filing that may be required for the establishment of the section 102(d) or 108 base rate.

Finally, § 157.40 of the regulations is amended herein to provide that small producers may charge the rate prescribed in sections 102(d) and 108 of the NGPA pursuant to the blanket certificate provided for in § 157.40(b).

The Commission is making these amendments effective upon the date of issuance upon a finding that good cause exists to proceed without compliance with the notice, public procedure, and effective date provisions of 5 U.S.C. 553. These changes in rate filing requirements must be immediately effective in order to avoid an unduly disruptive transition from the pricing rules established under the Natural Gas Act to those prescribed under the NGPA. For this reason, the Commission has found it necessary to make these amendments effective upon issuance of this order.

(Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.*; Department of Energy Organization Act, P.L. 95-91; E.O. 12009, 42 FR 46267.)

In consideration of the foregoing, Parts 154 and 157 of Subchapter E, Chapter I, Title 18, Code of Federal Regulations, are amended as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,047]

44 F. R. 21008 (April 9, 1979); 44 F. R. 24546 (April 26, 1979).

18 CFR Part 274

Amendment to the Filing Requirements for New, Onshore Production Wells

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: This rule amends the filing requirements for new, onshore production wells by modifying the form of the oath statement if the application is filed under 18 CFR 271.305, a special rule applicable to wells drilled in an existing proration unit. Two other clarifying amendments are also promulgated.

EFFECTIVE DATE: May 1, 1979.

FOR FURTHER INFORMATION CONTACT: Teresa Ponder, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 275-4236.

SUPPLEMENTARY INFORMATION: The Federal Energy Regulatory Commission (Commission) gives notice that it hereby amends 18 CFR 274.204. Section 274.204 is amended so that the required oath statement is consistent with the substantive requirements for a determination of eligibility with respect to wells which are drilled within an existing proration unit but qualify as new, onshore production wells under the special rule in 18 CFR 271.305.

I. Background

On December 1, 1978, the Federal Energy Regulatory Commission issued interim regulations implementing portions of the Natural Gas Policy Act of 1978 (NGPA) (43 FR 56448). Subpart C of Part 271 of the regulations implemented section 103 of the NGPA, setting forth substantive requirements for a determination that a well is eligible for the maximum lawful price applicable to "new, onshore production wells." Persons seeking a determination that a well qualifies under Subpart C must file applications for a determination with a jurisdictional agency. The filing requirements for such a determination are set forth in § 274.204 of the interim regulations.

It has come to the attention of the Commission that there is a discrepancy between the substantive requirements and the filing requirements. Generally, wells which qualify as new, onshore production wells under Subpart C of Part 271 are those which were drilled on or after February 19, 1977, and which were not drilled within an existing proration unit. However, § 271.305 of Subpart C contains a special rule under which certain wells drilled within an existing proration unit may still satisfy the statutory requirements and qualify for the maximum lawful price applicable to new, onshore production wells. The oath statement required in § 274.204 fails to reflect the possibility that a well may qualify under Subpart C of Part 271 of the regulations pursuant to the special rule in § 271.305. It requires that an application for a determination as a new, onshore production well include an oath statement that the well is not located within a proration unit.

A number of jurisdictional agencies have pointed out this discrepancy and requested clarification. Accordingly, the Commission will amend § 274.204 so that applicants need not file the complete oath statement for wells which fall within the scope of the special rule in Subpart C. More specifically, the amendment provides that with respect to wells eligible under § 271.305, i.e., wells drilled in existing proration units, the portion of the oath filing under § 274.204(d)(2) which relates to proration units may be omitted. The oath will still have to recite that the wells satisfy applicable federal or state well spacing requirements. Also, the information in § 274.204(f) would have to be submitted. Additionally, several applicants have pointed out confusing language in § 274.204(d)(4). As a result, the Commission has clarified the language so that an applicant may refer to the documents in the application as the basis for his conclusion that the well is a new, onshore production well.

Finally, paragraph (f) is corrected so that it refers to § 271.305 rather than § 271.304.

With respect to applications filed prior to the effective date of this regulation, the Commission will not treat as deficient any determination made under the special rule solely for the reason that the oath statement is incorrect with respect to this matter. This, of course, assumes that the application and determination are in all other respects complete and the requirements of § 274.204(d)(2)(f) are met.

II. Public Procedures and Effective Date

Part 274 was originally proposed for comments in November of 1978 and issued as an interim regulation on December 1, 1978 (43 FR 56448 (Dec. 1, 1978)). For 60 days thereafter comments were received and during that period public hearings were held on these regulations. The amendments to Part 274 contained in this order rest upon considerations given to the information received during the comment and hearing process. Furthermore, the amendments of this order will reduce unnecessary reporting burdens and provide for easier compliance with Part 274. For these reasons, good cause exists to proceed without further public notice and comment and to make these amendments effective May 1, 1979.

(Administrative Procedure Act, 5 USC § 553; Natural Gas Policy Act of 1978, Pub. L. 95-621.)

In consideration of the foregoing, the Commission amends § 274.204, Subchapter H, Part 274, Chapter 1 of Title 18, Code of Federal Regulations, as set forth below, effective May 1, 1979.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,048]

44 F. R. 24283 (April 25, 1979)

Ceiling Prices; Section 271.803—Definitions; Amendment to Interim Regulations

Issued: April 19, 1979.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Amendment to interim regulations.

SUMMARY: This rule amends § 271.803(b) of the Federal Energy Regulatory Commission's interim regulations implementing the Natural Gas Policy Act of 1978 (NGPA). By this amendment to its rules, the Commission is changing the permissible level of production relative to stripper well natural gas from "less than 60 Mcf" to "not more than 60 Mcf." This change will conform § 271.803(b) to § 108(b) of the NGPA.

EFFECTIVE DATE: April 19, 1979.

FOR FURTHER INFORMATION CONTACT: David D'Alessandro, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 275-4844.

SUPPLEMENTARY INFORMATION: On December 1, 1978, the Federal Energy Regulatory Commission (Commission) issued interim regulations (43 FR 56448, December 1, 1978), implementing the Natural Gas Policy Act of 1978 (NGPA), Pub. L. No. 95-621, 92 Stat. 3350. On January 3, 1979, the Commission issued Order No. 21 in Docket No. RM79-12 to establish a procedure for rehearing of Commission actions subject to the rehearing requirements in section 506 of the NGPA.

In reviewing a petition for rehearing filed by *Indicated Producers* pursuant to Order No. 21, the Commission was made aware of an error in section 271.803(b) of the interim regulations.[1] Section 108(b) of the NGPA defines, in part, stripper well natural gas as gas from a well which produces non-associated natural gas at a rate which did not exceed an average of 60 Mcf per production day during a 90 day production period. In the table in section 271.803(b), which sets out the various levels of production relative to the amount of crude oil allowed to be produced in association with stripper well gas, we have inadvertently limited the level of production to less than 60 Mcf per day when in fact it should have provided, consistent with the definition in section 108(b) of the NGPA, for not more than 60 Mcf per day.

Accordingly, the Commission is amending section 271.803(b) of the interim regulations to provide that the average production of natural gas per day is to be not more than 60 Mcf.

Effective date: The Commission is making this amendment effective upon the date of issuance of this order upon a finding that good cause exists to proceed without compliance with the notice, public procedure, and effective date provisions of 5 U.S.C. 553. The amendment does not make any substantive changes to the regulation, but merely corrects an inadvertent error to conform the regulation to section 108 of the NGPA. Thus good cause exists to make this amendment effective upon issuance of this order.

(Administrative Procedure Act, 5 U.S.C. 551, Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat 3350, Department of Energy

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[1] The Commission is today simultaneously issuing an order granting in part and denying in part *Indicated Producers* petition for rehearing with respect to section 271.803(b) of the interim regulations.

Organization Act, Pub. L. 95–91. (E.O. 12009. 42 FR 46267).

In consideration of the foregoing, Part 271 of Subchapter H, Chapter I, Title 18, Code of Federal Regulations, is amended as set forth below.

By the Commission.

Lois D. Cashell,
Acting Secretary.

[¶ 30,049]

44 F. R. 24825 (April 27, 1979)

18 CFR Parts 3, 157

Certification of Pipeline Transportation for Certain High Priority Uses

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: The Federal Energy Regulatory Commission is promulgating a final rule to implement Section 608 of the Public Utilities Regulatory Policies Act of 1978. The rule establishes procedures for the certification of transportation of natural gas purchased by agricultural or other high-priority users directly from producers.

EFFECTIVE DATE: April 23, 1979.

FOR FURTHER INFORMATION CONTACT: Robert C. Platt, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, 202–275–0161.

SUPPLEMENTARY INFORMATION:

I. Introduction

This rule implements, in part, the direct sale provision of the Public Utilities Regulatory Policy Act of 1978 (PURPA), Pub. L. 95–617, section 608, in conformance with the curtailment policies expressed in section 401 of the Natural Gas Policy Act of 1978 (NGPA), Pub. L. 95–621. Section 401 of the NGPA recognizes the high curtailment priorities of consumers such as residences, small commercial establishments, schools, hospitals, and essential agriculture users. Section 608 of PURPA adds Section 7(c)(2) of the Natural Gas Act to provide for the transportation of natural gas sold by a producer to an eligible user or produced and consumed by an eligible user (hereinafter referred to as "direct sale gas").

The Commission issued a Notice of Proposed Rulemaking in this Docket on February 5, 1979.[1] Public hearings were held on the proposal in Amarillo, Texas (on March 9, 1979), Little Rock, Arkansas (on March 16, 1979), Madison, Wisconsin (on March 16, 1979), San Francisco, California (on March 6, 1979), and Washington, D.C. (on March 13 and 14, 1979). Representatives of the United States Department of Agriculture and the United States Department of Energy participated on the hearing panels. This final rule is based upon the record compiled at these hearings, as well as the written comments submitted in this docket.

II. Summary of Comments

The February 5, 1979 Notice specifically sought comments on a number of issues including: (1) The expansion of the direct sales program into other areas, (2) the shifting of filing requirements from the pipelines onto the end users, (3) the appropriate length of certificate terms, (4) the possible interruption of direct sale deliveries to permit service to higher-priority users, and (5) various eligibility requirements for participation in the program.

A. *Expansion of User Eligibility.*—Some comments suggested expanding the program to serve process and feedstock users and to displace the consumption of imported fuel oil. The Commission will address the curtailment priority of non-agricultural process and feedstock users by implementing NGPA section 402. The eligibility of such users to participate in a direct sales program is deferred to permit consideration of their needs in light of the NGPA section 402 regulations and other pending proposals with respect to direct sales policies. The use of direct sale gas to displace imported fuel oil is now being considered in Docket No. RM79-34. Should the Commission later decide to permit other users to be included in the program, the resulting amendments would not disrupt transactions commenced under this subpart.

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[1] 44 FR 7740 (February 7, 1979).

Such a step-by-step implementation of PURPA section 608 is prudent. As noted by some commentors, purchasers of direct sale gas may well be competing with interstate pipelines for supplies. Yet the Commission's direct sale program is designed to supplement and not to supplant the existing markets for natural gas. A step-by-step implementation process will enable the Commission to monitor the markets and avoid potential disruption.

Several comments advocated stricter eligibility requirements by imposing an alternative fuel test. NGPA section 401(b) specifies that the curtailment priority for essential agricultural uses does not apply when an alternative fuel is economically practicable and that the fuel is reasonably available. Although NGPA section 401(b) imposes this alternative fuel test upon essential agricultural users which seek priority access to low-cost pipeline system supplies, the policy underlying that test does not apply to direct sales. Congress fashioned NGPA section 401 to provide essential agricultural uses with a high-curtailment priority to the maximum extent practicable within the context of existing curtailment plans. Unlike curtailment priorities, direct sale gas is not allocated at the expense of other consumers. Hence, the public policy of affording a priority treatment to schools, hospitals, and essential agricultural uses can be implemented under this program without regard to alternative fuel capability. Such an approach has the added advantage of eliminating the practical difficulties of determining the alternative fuel capability of loads not previously classified in curtailment proceedings.

B. *Application Procedure.*— Several comments noted the practical difficulties in implementing direct sales transactions and observed that the application requirements placed upon a pipeline applicant posed an obstacle to participation by pipelines. The proposed rule eased the burden on the pipeline applicant by permitting the eligible user to apply on its behalf. The final rule would permit either the pipeline or the end user to file for transportation authority. In addition, the final rule clarifies the fact that the pipeline, the eligible user, or any other party may request a rehearing of the Commission's order on the application.

C. *Term.*—The proposed five-year certificate term drew varied reactions. Some parties contended that a five-year term, even with the option of renewal, did not provide the necessary certainty required to justify substantial investment in new plant and equipment. Others argued that given the changing nature of the natural gas industry and the undesirability of making long-term commitments of pipeline capacity, a shorter term may be preferable. The Commission finds that a five-year maximum term is reasonable. Parties with capacity concerns remain free to apply for certificates of shorter duration.

Some comments requested that reserves purchased in place by eligible users should qualify for certificates which last for the life of the reserves. Because this is an issue in a pending adjudication, Docket No. CP77-71, the Commission will defer the decision on this issue.

D. *Emergency Service to High Priority Users.*—The Commission sought comment upon the desirability of conditioning certificates with an interruption requirement. This condition would permit a pipeline to divert direct sale gas to serve high-priority users when curtailment of pipeline system supplies to these users was imminent. Some of the comments noted that the President has the authority to redirect direct sales gas during declared natural gas supply emergencies under NGPA section 303(d). Because the President may declare natural gas supply emergencies on a regional basis, the

Commission views NGPA section 303(d) as offering sufficient flexibility to respond to emergency situations at this time.

Although NGPA section 303(d) provides for supply curtailment emergencies, capacity curtailment poses a separate problem. The Commission considers the interruption of direct sales gas deliveries as a result of pipeline capacity limitations to be a matter best left to the contractual negotiations between the parties.

E. *Relationship With Existing Programs.*—A number of comments suggested clarification of the direct sale program's relationship to the Commission's other regulations. In general, all applicable regulations apply unless expressly waived in the final rule. Hence, no provision for the interim collection of an incentive price by a producer is necessary, since NGPA section 503(c) and §§ 273.202 and 273.203 of this chapter provide for such collections pending the determination of a maximum lawful price. Similarly, the general procedures stated in Subpart A of Part 157 concerning certificate applications apply and need not be restated in this rule.

Several comments suggested adding additional eligibility requirements. Some have suggested that an eligible user who is served by a distributor must file an affidavit that the distributor cannot serve the user from the distributor's sources of supply. The Commission views such a filing requirement as unnecessary. User-distributor discussions are ensured by both the execution of the distributor's transportation contract and the filing of a statement by the distributor that it has capacity sufficient to perform the transportation services without detriment or disadvantage to its other customers (§ 157.103(d)). In addition, the price differential between the distributor's rolled-in systems supplies and the more expensive direct sale gas makes competition between direct sales and firm service by a distributor unlikely. Instead, the direct sale program established by this rule serves to complement the other services provided by distributors, within the framework of the applicable state regulation.

Similarly, the direct sale program complements the role of the interstate pipelines in meeting their customer's needs. Interstate natural gas pipelines are not common carriers,[2] and their participation in this program is voluntary. However, several commentators note that some interstate pipelines have excess capacity which although not being utilized to meet the needs of current customers is being paid for by the pipeline's ratepayers. Direct sales programs offer interstate pipelines an opportunity to utilize unused capacity and to reduce the burden upon their ratepayers.[3] If an interstate pipeline is unwilling to avail itself of such opportunities, it becomes difficult to see why the ratepayer should continue to bear this burden. However, if necessary, such considerations are best addressed in individual rate proceedings where all facts can be fully developed.

In summary, we have concluded that the public interest is best served by accommodating customer requirements through pipeline system supply. Such an approach offers both economic and administrative advantages to the pipelines as well as reducing the regulatory burden of approving transactions on a case-by-case basis. However, a direct sale program is appropriate to serve high priority uses which cannot be served through pipeline system supplies.

F. *Eligibility of Gas Reserves.*—Several parties request that Outer Continental Shelf (OCS) gas should be eligible for participation in the direct sale program. In addition, the First Mississippi Corporation contends that excluding OCS gas from the program is "unlawful."[4]

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[2] See NGPA Section 602(b).

[3] Section 157.105(g) requires the Part 284 rate to be used. Section 284.103(d) requires revenues in excess of out-of-pocket costs to be flowed through the ratepayers in Account 191.

[4] Washington Public Hearing transcript at 237.

The Commission views First Mississippi's legal objection to be without merit. First, the requirement that the reserves must not be "committed or dedicated to interstate commerce"[5] is subject to waiver under § 157.104(b). Although request for waivers will receive careful consideration in light of the public interest served by the individual transactions, the Commission considers the § 157.104(a) general eligibility rule to be necessary in order to provide guidance to parties in planning transactions. Second, the courts have repeatedly held that the Commission has discretion in evaluating the present and future public convenience and necessity of transportation of direct sale gas. In the context of direct sales, the Commission may consider,

> "among other factors, those of end use, preemption of pipeline facilities and price. * * *" (*F.P.C. v. Transcontinental Gas Corp.*, 365 U.S. 1, 31 (1961)).

Given the special nature of OCS gas and the pipeline facilities used to bring such gas onshore, the Commission acts within its discretion by cautiously approaching direct sales of OCS gas.

The "committed or dedicated" test adopted in § 157.104(a) furthers several important policies. The Commission seeks to avoid disruption of OCS supply patterns. Such disruptions are particularly undesirable in light of pending litigation.[6] In addition, the public interest is best served when low-cost "committed or dedicated" reserves are allocated according to priority of use within the framework of state-approved or FERC-approved curtailment plans. Continued allocation of "committed or dedicated" reserves according to the terms of such plans will protect existing high-priority uses. In contrast to the policy considerations which resulted in the assignment of a high-curtailment priority to residential and other uses, the eligible uses served by the direct sale program do not have as compelling an equitable claim to the traditional sources of interstate pipeline system supply. At this time of transition toward the new regulatory patterns established by the NGPA, the Commission is not prepared to jeopardize the availability of low-cost supplies to existing customers to make such gas available through direct sales to new customers or to existing customers seeking increased loads.

The selection of the "committed or dedicated" test is predicated upon an additional policy consideration. NGPA section 315(b)(3) gives interstate pipelines the opportunity to match the terms of a sales agreement "substantially accepted in principle" by a competing buyer. Because "committed or dedicated" gas is ineligible for transportation in the proposed direct sale program, and because section 315(b)(3) applies only to gas which is "committed or dedicated," the test prevents the direct sales program from affecting the contract terms available to interstate pipelines under section 315(b)(3).

For these reasons, the Commission will consider the use of "committed or dedicated" reserves only on a case-by-case basis under the waiver provision of § 157.104(b).

III. Summary of Final Rule

Subpart E of Part 157 supplements the Commission's existing direct sale authorization of allowing the transportation of direct sale gas to certain users that may not currently be eligible to have natural gas transported under 18 CFR 2.79.

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[5] All OCS gas is defined to be "committed or dedicated" by NGPA section 2(18)(a)(i). The Commission recognizes that the "committed or dedicated" standard is applied to OCS gas in the NGPA for jurisdictional and pricing purposes only. While the legal application of the definition is limited to 16 substantive NGPA provisions, the test still represents the most practicable test for classifying reserves in a manner which will achieve the Commission's policy objectives. Many producers would have previously applied this test when filing under the NGPA interim collection procedures as set forth in § 273.201(c)(2) and § 273.202(d)(1)(v) of this chapter.

[6] *See, Air Products & Chemicals, Inc.* v. *F.E.R.C.*, 5th Cir., Docket No. 78-2011, and *Public Service Commission of the State of New York* v. *F.E.R.C.*, D.C. Cir., Docket No. 78-1572.

Section 157.101 indicates the manner in which such direct sale authority is implemented. Subpart E would permit the transportation of direct sale gas to all essential agricultural users as certified by the Secretary of Agriculture and all schools, hospitals, and similar institutions.

A transportation certificate under section 7(c)(2) of the Natural Gas Act would be issued to the transporting interstate pipeline. However, as indicated in § 157.10(a), either the pipeline or the eligible user on behalf of the pipeline may make application for the certificate. Because the application must include executed contracts, applications cannot be filed until the producer, pipeline, eligible user, and any distributor all consent to the transaction.

Applications for a permanent certificate may include application for a temporary transportation certificate. All applications will be processed on an expedited basis. Although section 7(c)(2) of the Natural Gas Act makes no explicit provision for temporary certificates, section 16 of the Natural Gas Act is sufficient legal authority for the Commission to grant such temporary certificates. (See *Hunt Oil Company* v. *F.P.C.*, 334 F.2d 474 (5th Cir. 1964).)

Temporary certificates may be issued by the Director of the Office of Pipeline and Producer Regulation. This delegation is achieved by including a conforming amendment to § 3.5(f)(1)(iv) of this chapter in this rulemaking. Permanent certificates will be issued by the Commission after notice, an opportunity for protest and, where appropriate, a hearing.

Secton 157.101(c) assures that the pipeline, the eligible user, as well as any other party will have the opportunity to seek rehearing of a Commission order acting upon the application.

Section 157.102 defines "eligible uses" to include any use certified as an "essential agricultural use" by the Secretary of Agriculture pursuant to section 401(c) of the NGPA, and uses by hospitals and schools or similar institutions as those terms are defined in §§ 281.103(b)(2) and (3) of this chapter. These definitions reflect the priorities of section 401 of the NGPA. An "eligible user" is defined as anyone who consumes natural gas for an eligible use. Residential and small commercial users have historically been protected from curtailment of service from general pipeline supplies, and NGPA section 311(a) provides these users further protection through local distribution companies. As a result, they do not require the access to direct sales provided under the final rule. Additionally, the large number of such users in this category could not be accommodated practically under the direct sale program.

The Commission has determined that its policy governing the transportation of direct sale gas should be expanded to include eligible users who are not facing curtailment, to serve new eligible users, and to supply the increased loads of existing eligible users.

A determination under NGPA section 401(b) by the Commission that an essential agricultural user has an available alternative fuel will have no effect upon that user's eligibility to have its direct sale gas transported. (See Part II(A) above). Thus, eligible users can utilize direct sale gas to replace other fuels, in whole or in part, to meet its energy requirements.

Congress, in section 401(f), elevated the previously low-priority boiler fuel use by schools and hospitals to high-priority status. Such a change reflects a shift from "end-use" to "end-product" tests in determining curtailment priorities for the uses designated in NGPA section 401. The Department of Agriculture has used an "end-product" test as the sole criterion for defining "essential agricultural uses" in its Interim Final Rule.[7] The Commission has applied this same test in its proposed definition of "eligible uses" for direct sale gas transportation.

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[7] 7 CFR Part 2900, 44 FR 11518 (March 1, 1979). Although some end-use tests are incorporated into the Department of Agriculture's certification of Essential Agricultural Volumetric Requirements in 7 CFR 2900.4, such requirements are not incorporated into the 7 CFR 2900.3 test used here.

Section 157.102(c) is an exercise of the Commission's rulemaking authority under section 7(c)(2) of the Natural Gas Act. It determines that "high-priority uses" shall include eligible uses as defined in § 157.102. Section 157.103 sets out the data that must be supplied in an application for direct sale transportation authorization.

Section 157.104 limits the type of gas that qualifies for direct sale transportation by reliance upon the "committed or dedicated" test defined in NGPA section 2(18). This test is designed to prevent the disruption of the offshore supply patterns and to preserve low-cost supplies for interstate system supply. Proposed § 157.104(a) applies the "committed or dedicated" test as of November 8, 1978. This date is used for applying the test because it is used in pricing determinations under NGPA section 104, 105, 106, and 109 and in deciding which natural gas is subject to the right of first refusal under NGPA section 315(b). (See Part II(F) above.)

Should an applicant wish to transport direct sale gas that is ineligible for transportation under § 157.104(a), paragraph (b) authorizes a request for a waiver of the § 157.104(a) requirement. For example, the Commission could consider waivers for "committed or dedicated" gas classified under NGPA section 107, even though such natural gas does not qualify under § 157.104(a).

Section 157.105 establishes general conditions that are automatically incorporated into any certificates issued under the proposed rule.

The maximum term for the certificate is five years. The five-year term reflects several considerations. First, comments received during the Commission's consideration of 18 CFR 2.79 indicate that more than two years are required to attract many of the potential sources of new gas supplies. Second, users served by this program do not require more frequent recertification, as their progress toward conversion to alternative fuel is not a consideration under this program. Third, a number of optimistic supply projections have recently been put forward and, if correct, could provide a basis for extending the maximum term. On the other hand, natural gas production is in an evident period of transition and uncertainty. The public interest would not appear to be served by long-term transportation commitments, at this time.

The Commission will entertain requests for a ten-year term in applications by the users who develop and produce their own reserves. However, the ten-year term will not be available to eligible users who merely acquire reserves-in-place. This longer certificate term is intended to provide eligible users an incentive to develop new natural gas supplies.

Under § 157.105(b), a pipeline may apply for a renewal certificate. Such reapplication will be reviewed *de novo*. Thus, an eligible user who enters into a contract for the purchase of direct sale gas for a period of more than five years does so at its own risk. Paragraph (c) provides a six-month grace period to permit delivery of volumes beyond the end of the certificate's term if the producer contract includes a take-or-pay provision.

Section 157.105(d) requires an acceptance of the certificate to be filed only by the interstate pipeline company. The eligible user, the producer, and any nonjurisdictional transporter of the direct sale gas are deemed to consent to the transportation certificate through their execution of the contracts filed with the application. Under paragraph (e) if the gas is diverted to uses other than the eligible uses, the certificate authorization ceases and any further deliveries by the pipeline would be in violation of the Natural Gas Act. While interstate pipelines cannot completely monitor the end-uses of their customers, the sanctions of Natural Gas Act section 21 will apply to any pipeline which willfully and knowingly continues to transport direct sale gas to a customer who has diverted gas from eligible uses.

Paragraph (f) requires the eligible user to file an annual report within 60 days of the anniversary of the issue date of the certificate. The report will deter possible diversion of direct sale gas from eligible uses.

Paragraph (g) requires the interstate and intrastate pipelines transporting direct sale gas to use the same rate methodology that applies to transportation under section 311(a) of the NGPA. This rate methodology is also used in the recently promulgated emergency purchase regulations (Subpart C of Part 157).

(Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.* Public Utilities Regulatory Policies Act of 1978, Pub. L. 95-617, Natural Gas Policy Act of 1978, Pub. L. 95-621, Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 43 FR 46267).

In consideration of the foregoing, Chapter I of Title 18, Code of Federal Regulations, is amended as set forth below.

By the Commission.

Lois D. Cashell,
Acting Secretary.

[¶ 30,050]

44 F. R. 26067 (May 4, 1979)

18 CFR Parts 35 and 154

Final Regulation Modifying the Time Limit for Commission Action on R.D. & D. Plans

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: The Order amends 18 CFR 35.22(d) and 154.38(d)(5)(iv) to allow 120 days, rather than the current 90 days, for Commission action on an application for advance approval of a research, development and demonstration (R.D. & D.) program to allow for a more thorough analysis of the application.

EFFECTIVE DATE: May 29, 1979.

FOR FURTHER INFORMATION CONTACT: Bruce A. Connell, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 275-4802.

SUPPLEMENTARY INFORMATION: On February 2, 1979, the Commission issued a Notice of Proposed Rulemaking in this docket, proposing to amend 18 CFR 35.22(d) and 154.38(d)(5)(iv) to allow 120 days, rather than the current 90 days, for Commission action on an application for advance approval of a research, development and demonstration (R.D. & D.) program.

Comments were invited from interested parties on or before March 15, 1979. Timely comments were received from the Gas Research Institute (GRI) and Kadane Oil Company (KOC). Comments of the people of the State of California and the Public Utilities Commission of the State of California (California) were filed on March 26, 1979.

Background

In order to receive advance approval of an R.D. & D. program for a given year, an R.D. & D. organization or a jurisdictional company seeking such approval must submit a five year R.D. & D. plan at least 180 days prior to the commencement of the program. Under the Commission's current regulations, 18 CFR 35.22(d) and 154.38(d)(5)(iv), the Commission must act upon the R.D. & D. plan within 90 days after it is filed.

On June 30, 1978, the Gas Research Institute (GRI) submitted a proposed research and development program which was approved in Opinion No. 30.[1] The People of the State of California and the Public Utilities Commission of the State of California (California) filed a comment in the GRI docket criticizing the short timetable imposed as a result of the 90-day deadline. California suggested that the Commission's review

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[1] *Gas Research Institute*, "Opinion and Order Approving the Gas Research Institute's 1979 Research and Development Program," Docket No. RP78-76, issued September 21, 1978.

of subsequent GRI applications would be "substantially enhanced by a modest amendment of the Commission's regulations" to allow 120 days for Commission action on an application for advance approval of an RD&D program. In Opinion No. 30 the Commission stated that it would issue a Notice of Proposed Rulemaking to obtain comments on California's proposal.

GRI supports the modification from 90 days to 120 days but would strongly oppose any period longer than 120 days. GRI objects to any schedule which would provide for the filing of comments by parties as to which GRI would not have an opportunity to reply. KOC objects to the modification from 90 days to 120 days, stating that such additional time is unnecessary. California strongly supports the modification and reaffirms its support for its proposed procedural schedule.

California also suggested a schedule for handling GRI's next annual application. Assuming that GRI submits its next application on June 4, 1979 in order to obtain Commission action by October 1, 1979, California proposed that initial comments and a staff report be filed on July 13, 1979. Reply Comments by CRI would be filed on August 3, 1979, and further comments would be filed on August 24, 1979.

In the February 2, 1979, Notice of Proposed Rulemaking, the Commission stated:

> The Commission notes, however, that comments on procedures to be followed in handling GRI's application are solicited through this Notice of Proposed Rulemaking only so that the Commission will have the comments available when it establishes a procedural schedule after GRI files its next annual application in 1979. This is not a rulemaking to establish a particular procedural schedule. The rulemaking proposed herein only revises the 90-day deadline to 120 days. (mimeo p. 3) emphasis added.

Accordingly, we will defer ruling on the appropriate schedule for GRI's next annual application at this time.

The proposed amendment to the Regulations will provide the Commission a better opportunity to review GRI's application together with the comments of interested parties without prejudice to any party. Thus, the Commission finds that good cause exists for revising the Regulations as proposed.

[Federal Power Act, as amended, 16 U.S.C. 792 *et seq.*, Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.*, Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267, Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350]

In consideration of the foregoing, the Commission is amending § 35.22(d) of Part 35, Subchapter B, Chapter I, of Title 18 and § 154.38(d)(5)(iv) of Part 154, Subchapter E, Chapter I of Title 18 of the Code of Federal Regulations as set forth below, to be effective 30 days from date of issuance.

By the Commission.

Lois D. Cashell,
Acting Secretary.

[¶ 30,051]

44 F. R. 26068 (May 4, 1979)

18 CFR Parts 271 and 273

Amendment to Regulations Relating to Publication of Prescribed Maximum Lawful Prices Under the Natural Gas Policy Act of 1978

April 27, 1979.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: This rule amends certain sections of the Commission's Regulations implementing the Natural Gas Policy Act of 1978. By this amendment the Commission is issuing a compilation of Prescribed Maximum Lawful Prices under NGPA for the months of May, June and July, 1979. Section 101(b)(6) of the NGPA requires that the Commission compute and make available prices and inflation adjustments at least five days before the beginning of any month for which such figures apply.

EFFECTIVE DATE: April 27, 1979.

FOR FURTHER INFORMATION CONTACT: Mark Magnuson, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426. (202) 275–4850.

SUPPLEMENTARY INFORMATION:

A. Background

On December 1, 1978, the Federal Energy Regulatory Commission (Commission) issued Interim Regulations (43 FR 56448, December 1, 1978), implementing the Natural Gas Policy Act of 1978 (NGPA), Pub. L. No. 95–621, 92 Stat. 3350.

On January 25, 1979, the Commission issued the Publication of Prescribed Maximum Lawful Prices Under the NGPA and Amendments to Regulations Relating to Minimum Rate Gas. (Docket Nos. RM79–3 and 79–4).

Sections 271.101(a), 271.202, 271.302, 271.402(a), 271.402(c)(4), 271.602, 271.702, 271.802, 271.902, and 273.201(a)(1) of the Commission's regulations under the NGPA set forth maximum lawful prices per MMBtu (Mcf for minimum rate gas) for deliveries made in December, 1978, through April, 1979. Section 271.102(c) sets forth the monthly inflation adjustment factors. Section 101(b)(6) of the NGPA requires that the Commission compute and make available maximum lawful prices and inflation adjustments at least five days before the beginning of any month for which such figures apply. Pursuant to that mandate, the Commission hereby amends its regulations implementing the NCPA to add to the existing price tables, prices and inflation adjustments for the months of May, June, and July 1979.

B. Summary of Amended Regulations

The Commission's regulations under the NGPA are being modified to include the maximum lawful prices and inflation adjustments for May, June, and July 1979. The subparts of Part 271 of Subchapter H of the interim regulations so affected, and the types of natural gas to which these subparts apply, are as follows: Subpart A—Summary Tables and Calculations (§§ 271.101(a) and 271.102(c)); Subpart B—New Natural Gas and Certain Natural Gas Produced from the Outer Continental Shelf (§ 271.202); Subpart C—New, Onshore Production Wells (§ 271.302); Subpart D—Natural Gas Committed or Dedicated to Interstate Commerce (§ 271.402(a), (§ 271.402(c)(4)); Subpart F—Intrastate Rollover Contracts (§ 271.602); Subpart G—High-Cost Natural Gas (§ 271.702); Subpart H—Stripper Well Natural Gas (§ 271.802); and Subpart I—Other Categories of Natural Gas (§ 271.902). Further, Part 273 of Subchapter H is amended by publishing the maximum lawful prices for May, June, and July, 1979 to Subpart B—Interim Collection Authority (§ 273.201(a)(1)).

C. Effective Date

The Commission is making these amendments effective upon the date of issuance of this order upon a finding that good cause exists to proceed without compliance with the notice, public procedure and effective date provisions of 5 U.S.C. § 553. The GNP Implicit Price Deflator computed and published by the Department of Commerce for the most recent calendar quarter is published at least 8 days before the beginning of each quarter. Section 101(b)(6) of the NGPA requires that maximum lawful prices and inflation adjustments be made available by the Commission at least five days before the beginning of the month to which they apply. Unless amendments regarding rate changes for May, June and July 1979 are made effective immediately producers may bill and file incorrectly for the affected categories of gas. Thus, good cause exists to make these amendments effective upon issuance of this order. In addition, for the above mentioned reason, the Commission believes good cause exists to dispense with public comment procedures.

(Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. 791, *et seq.*, Federal Energy Administration Act, 15 U.S.C 761, *et seq.*, Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267).

In consideration of the foregoing, Parts 271 and 273 of Subchapter H, Chapter I, Title 18, Code of Federal Regulations, are amended as set forth below, effective immediately.

By the Commission.

Lois D. Cashell,
Acting Secretary.

[¶ 30,052]

44 F. R. 26854 (May 8, 1979)

18 CFR Part 154

Natural Gas Policy Act of 1978; Order Extending Time To File Protests and Clarifying Prior Order

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Order Extending Time.

SUMMARY: The Federal Energy Regulatory Commission amends its regulations by extending the deadline for the filing of protests to blanket affidavits and interim collection filings. This will enable more time for an interested party to challenge contractual authority to collect a maximum lawful price under the Natural Gas Policy Act of 1978.

EFFECTIVE DATE: April 30, 1979.

ADDRESSES: All filings should reference Docket No. RM79-22 and should be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Phil Yates, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 275-4212.

On March 13, 1979, the Commission issued Order No. 23 in Docket No. RM79-22 (44 FR 16895, March 20, 1979). Order No. 23 dealt generally with the question of contractual authority to collect maximum lawful prices under the Natural Gas Policy Act of 1978 (NGPA).[1] Apart from that question was the procedural issue of how an interested party could protest the collection of an NGPA maximum lawful price if that interested party asserted that the applicable contract did not provide the requisite authority to collect the price.

In Order No. 23 we stated:

> [T]he Commission will establish a general protest procedure in which parties in interest can petition the Commission for a specific determination as to whether a particular contractual clause constitutes the requisite authority to charge and collect Natural Gas Policy Act rates. In light of the administrative difficulties, complexities and general practical problems which attend the transitional period, the Commission will amend its protest procedures contained in § 154.94 to allow for filings of protests within the latter of 90 days after filing of an affidavit, or May 1, 1979. Similarly, protest to interim and retroactive collection filings may be filed within the latter of 90 days of the

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[1] Pub. L. 95-621, 92 Stat. 3350.

[2] Order No. 23, mimeo at 52.

filing of notice to the Commission, or May 1, 1979. The Commission, for practical administrative reasons and in order to give some certainty to these matters, will not entertain protests filed after that date. Of course, parties in interest may still be able to resort to the courts to seek resolution of the question.[2]

Requests for clarification of Order No. 23 were filed by the Associated Gas Distributors (AGD), and by the New York Public Service Commission (NYPSC). Several issues were raised in each request for clarification, but only two require immediate Commission action.

AGD requested that the May 1, 1979, deadlines for filing protests be extended, due to the practical difficulties in complying with that date in light of the large number of natural gas contracts which may be the subject of protests. We agree that the practical difficulties in meeting the May 1, 1979, deadlines are substantial. Accordingly, the Commission finds that good cause exists to amend § 154.94 to extend the date for the filing of protests from May 1, 1979, to June 15, 1979. In light of our extension of the dates for filing protests, we do not consider further AGD's motion for emergency procedural relief or its motion for stay of Order No. 23.[3] The Commission is evaluating the pleadings suggesting that the present protest procedure is inadequate,[4] and will issue a notice requesting comments on possible changes to that procedure. If the Commission has not completed its evaluation in advance of the expiration of the 45 day extension, it will further extend the time for the filing of protests; if the protest procedure is modified, the Commission will allow a reasonable time for the filing of protests under the procedure adopted.

The other issue the Commission must address is the request by NYPSC and AGD that Order No. 23 be clarified to indicate that failure to protest a jurisdictional agency determination[5] will not waive an interested party's right to contest an issue of contractual authority. The Commission does not consider a jurisdictional agency determination of a well's NGPA pricing category to have any relevance to the question of contractual authority to collect the maximum lawful price for that category. Thus the Commission agrees that "the procedures for protesting producer claims to contractual authority to charge NGPA ceiling rates are independent of the Commission's review proceedings with respect to determinations by jurisdictional agencies pursuant to Section 503 of the NGPA."[6]

(Natural Gas Act as amended, 15 U.S.C. 717, *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. 761, *et seq.*, Natural Gas Policy Act of 1978, Pub. L. 95–621, 92 Stat. 3350, Department of Energy Organization Act, Pub. L. 95–91, E.O. 12009, 42 FR 46267.)

In view of the need for prompt Commission action in these circumstances to provide an opportunity to file challenges to contractual authority, and since notice and opportunity for comment are impracticable, unnecessary and contrary to the public interest, the Commission finds that good cause exists to issue these amendments without opportunity for notice and public procedure thereon. For the same reasons, good cause exists to issue these regulations effective immediately.

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[3] This order does not deny these motions: they remain before the Commission for such further consideration as may be appropriate. Nor shall such motions be deemed denied by the decision to postpone action thereon. *Cf.* 18 CFR 1.12(e) (motion made after hearing commenced deemed denied if Commission does not act within 30 days of filing or referral).

[4] E.g. Application of the Public Service Commission of the State of New York for Rehearing of Order No. 23; Petition of the State of Michigan and the Michigan Public Service Commission for Rehearing of Order No. 23. Both filings were made on May 12, 1979, in Docket No. RM79–22.

[5] Section 275.201(d) of the Commission's regulations requires a protest to a jurisdictional agency determination to be filed within fifteen days.

[6] NYPSC's Request for Clarification, at page 4.

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In consideration of the foregoing. Part 154 of Subchapter E. Chapter I. Title 18, Code of Federal Regulations. is amended as set forth below.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,053]

44 F. R. 26855 (May 8, 1979)

18 CFR Part 281

Natural Gas Curtailment; Implementation of Section 401 of the Natural Gas Policy Act

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) completes the Commission's process of establishing rules to carry out its statutory responsibilities under Section 401(a) of the Natural Gas Policy Act of 1978 (NGPA). It establishes a permanent curtailment rule which provides that to the maximum extent practicable curtailment plans of interstate pipelines protect deliveries of natural gas for "essential agricultural users" and for "high-priority users" as these terms are defined in Section 401(f)(2) of the NGPA.

EFFECTIVE DATE: June 7, 1979.

FOR FURTHER INFORMATION CONTACT: Mary Jane Reynolds, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8000, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 275–4283.

Background

Section 401 of the Natural Gas Policy Act of 1978 (NGPA) seeks to assure that natural gas required for essential agricultural uses will not be curtailed unless curtailment is required to protect the needs of certain enumerated high priority users. Section 401 of the NGPA establishes a curtailment scheme where the Secretary of Agriculture (USDA) determines the volumetric amounts required by essential agricultural users, the Secretary of Energy establishes curtailment priorities and the Federal Energy Regulatory Commission (Commission) establishes procedures whereby the curtailment plans of interstate pipelines carry out the Congressional policy to provide agricultural users certain protections from curtailment. The rule promulgated herein completes the Commission's process of promulgating rules to carry out its statutory responsibilites under Section 401(a) of the NGPA. A rule proposing procedures for alternate fuel determinations under Section 401(B) is the subject of a separate rulemaking in Docket No. RM79–40.

Specifically, the Commission must implement the USDA and Economic Regulatory Administration (ERA) rules so that, to the maximum extent practicable, no curtailment plan of an interstate pipeline results in curtailment of deliveries of natural gas for any essential agricultural use, below the requirement specified by the USDA unless such curtailment is necessary in order to meet the requirements of high-priority users, as that term is defined in Section 401(f)(2) of the NGPA.

Title IV of the NGPA creates new priority classifications for high-priority uses as defined in the statute. These are "essential agricultural uses", and "essential industrial process and feedstock uses". The ERA of the Department of Energy is studying curtailment priority policy and will likely propose rules to implement Section 402 at some future time. However, it does not appear that ERA will have done so in time to be coordinated with implementation of Section 401.

Section 401(a) provides that not later than 120 days after the date of enactment of the NGPA the Secretary of Energy shall prescribe and make effective a rule which provides that no curtailment plan of an interstate pipeline may provide for curtailment of deliveries of natural gas for essential agricultural use except to meet the requirements of enumerated high-priority users.[1]

Section 401(c) states that the USDA shall certify to the Secretary of Energy and to the Commission the natural gas requirements for essential agricultural uses in order to meet the requirements of full food and fiber production.[2]

Pursuant to Section 403(b) of the NGPA and Section 402(a)(1)(E) of the Department of Energy Organization Act, the Commission is charged with implementing the rules mandated by Section 401 under its authority to establish, review, and enforce curtailments under the Natural Gas Act. By a separate rulemaking the Commission has promulgated an Interim Rule to give effect to section 401 for the period April 1, 1979 to October 31, 1979. The permanent rule will be effective with respect to deliveries of natural gas for the winter heating season of 1979–80 and thereafter.

The interim rule promulgated by the Commission set forth a procedure whereby high-priority users and essential agricultural users can obtain relief from curtailment of the natural gas they use. In response to the interim rule interstate pipelines have filed tariff provisions which provide high-priority users and essential agricultural users relief from curtailment in a manner analagous to the existing life and property provisions that have long been common in pipeline tariffs. In contrast to the approach of having eligible users apply for additional supplies when necessary, the permanent rule provides protection by reordering the priority classifications in accordance with the priority system set forth in Section 401 of the NGPA. The reordering places high-priority users, as defined by the statute,[3] and essential agricultural users, as also defined by the statute, in new priority of service classifications 1 and 2, respectively.

In essence, the Commission is retrofitting existing curtailment plans to accommodate the new Congressional mandate in Section 401. In doing so, the Commission is not unmindful of the *State of North Carolina* v. *F.E.R.C.*, 584 F 2d 1003 (D.C. Cir. 1978) where an end-use curtailment plan was found deficient both because the natural gas was allocated using base period data which did not bear relationship to current end-uses of the natural gas, and because the Commission failed to consider the differing impact of the plan on full and partial requirements customers. However, *North Carolina* involved review of a curtailment plan implemented solely under the authority of the Natural Gas Act. In Section 401 Congress mandated that the Commission modify curtailment plans (which have been implemented under the NGA) to protect essential agricultural uses of natural gas, except to the extent the natural gas is necessary for high-priority uses. The Section 401 requirement is superimposed upon the Natural Gas Act standards for a curtailment plan. By Congressional mandate, it must be implemented notwithstanding the standards which have historically controlled determinatioin of lawfulness of curtailment plans under the NGA. Therefore, the Commission does not believe that *North Carolina* controls this rulemaking.

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[1] 44 FR 1526 (March 1, 1979).

[2] The USDA rule is an interim final rule, and the substantive provisions thereof may be changed in their [its] final rule.

[3] Section 401(f)(2)(C) defines high-priority use as gas used *inter alia* in a "school, hospital, or similar institution." The Commission has defined schools and hospitals broadly in lieu of defining "similar institution." Section 401(f)(2)(D) provides that high-priority uses also include "natural gas in any other use the curtailment of which the Secretary of Energy determines would endanger life, health, or maintenance of physical property". In accord with this provision, the Secretary of Energy has defined as high-priority use natural gas used "for minimum plant protection, for fire protection, in a sanitation facility, in a correctional facility, or for emergency situations pursuant to 18 CFR 2.78(a)(4)." 10 CFR 581.02(b)(6)(iv). Volumes of natural gas necessary for "minimum plant protection when the plant is shut down" and for "emergency situations pursuant to 18 CFR 278(a)(4)" are not based upon historical requirements for which entitlements can be appropriately calculated. Accordingly the rule requires every pipeline to include an emergency relief clause providing for delivery of such volumes. 18 CFR 281.204(c).

Moreover, in implementing Section 401, Congress has indicated that it does "not intend the reopening of curtailment plans for this limited purpose [of protecting essential agricultural requirements] to result in adoption of a new base year for curtailment purposes". Conf. Report No. 1752, 95th Cong. 2d Sess. 113 (1978). If the Commission were to apply the rule in *North Carolina* to the curtailment plans resulting solely from implementation of Section 401, it would necessarily require the Commission to reopen all existing curtailment plans which have been found just and reasonable. This result is both administratively infeasible and contrary to Congressional intent.

The Secretary of Energy and the USDA have promulgated the statutorily required rules. On March 9, 1979, the ERA promulgated a final rule wherein certain terms are defined, and wherein curtailment priorities as set forth in Section 401 of the NGPA are established. Likewise, the Secretary of Agriculture has promulgated an Interim Final Rule (44 FR 11526, March 1, 1979) which establishes the volumetric requirements for essential agricultural users. (7 CFR 2900.4)

To implement the statutorily mandated upgrading of priorities in accord with the USDA and ERA rule, the Commission issued a Notice of Proposed Rulemaking on January 12, 1979, in this docket. The deadline for filing Comments was March 20, 1979. Public hearings were held in various locations.[4] On the basis of the record established, including the written and oral comments received, the Commission has modified its initial proposal and now promulgates the rule contained herein.

The Commission has had the benefit of consultation with the USDA as contemplated by Section 401. This consultation has been extremely valuable to the Commission in its process of evaluating and determining the method by which to implement Section 401. The Commission is aware, however, that consultation does not imply concurrence by the USDA with all aspects of this rule.

The Rule

Under the permanent rule promulgated today, most customers—both direct customers and local distribution company customers—of interstate pipelines will be required to re-examine the data used to determine base period volumes for curtailment plans in order to identify which volumes meet the ERA's definition of priority 1. Only volumes whose deliveries are protected by the NGPA before deliveries to essential agricultural users will be included in priority 1. The rationale for this treatment stems from the Secretary of Energy's definition of "high-priority use" (Priority 1). In the ERA rule, "high-priority use" is not defined in the same manner as the definition of "high-priority use" in the currently effective curtailment plans of certain interstate pipelines. Schools, hospitals, and large apartment buildings included by ERA in priority 1 generally were not given priority 1 treatment in most interstate

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[4] March 6, 1979—California Public Utilities Commission, California State Building, 350 McAllister Street, San Francisco, California

March 9, 1979—Holiday Inn, 1911 I-40E at Ross, Amarillo, Texas

March 13 and 14—Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C.

March 16, 1979—Wisconsin Public Service Commission, 4802 Sheboygan Avenue, Madison, Wisconsin

March 19, 1979—Arkansas Public Service Commission, Justice Building, Little Rock, Arkansas pipeline plans. Likewise, some curtailment plans of interstate pipelines may have included in their priority 1 classification end-uses which are not categorized in the priority 1 category by the Department of Energy.

Pipeline curtailment plans will include a new priority 2 which will contain the requirements necessary to serve essential agricultural uses as defined by the Secretary of Agriculture.

The USDA interim rule defines volumetric requirements:

> § 2900.4 *Essential agricultural volume requirements.* (a) For purposes of section 401 of the NGPA, Essential Agricultural columetric Requirements are certified to be:
>
> (1) For each Essential Agricultural Use Establishment which (i) uses natural gas on farm for agricultural production, or (ii) consumes 300 mcf or less of natural gas per peak day (whether such Essential Agricultural Use Establishment is in existence on the effective day of this rule or comes into existence thereafter)—100 percent of the current requriements.
>
> (2) For each Essential Agricultural Use Establishment not inlcuded in paragraph (1) (whether such Essential Agricultural Use Establishment is in existence on the effective date of this rule or comes into existence thereafter)—the higher of:
>
> (i) The actual volume of natural gas used by such Essential Agricultural Use Establishment (corrected to include amounts of process and feedstock gas not used because of curtailment or plant shutdown) during the applicable period of the most recent 3 years (updated annually) which has the highest corrected volume; provided, however, that if any such Essential Agricultural Use Establishment shall have been in existence less than 3 years, the applicable period shall be that having the highest correct volume of such Essential Agricultural Use Establishment's existence; or
>
> (ii) the maximum volume such Essential Agricultural Use Establishment would be entitled to purchase under the interstate pipeline's curtailment plan in effect on the effective date of this rule.

The volumes included in the other priority classifications in an interstate pipeline's plan must be reduced to the extent that those volumes are now placed in new priorities 1 or 2. Uses not included in priorities 1 or 2 would be handled in accord with current curtailment plans, but deliveries of all such volumes would be given a lower preference than delivery of new priority 1 and 2 volumes.

The changes in curtailment plans are to be implemented on November 1, 1979. It will be necessary for the interstate pipelines to revise the volumes of natural gas reflected in each category or service in their curtailment plans in order to affect the changes brought about by the NGPA. Thus, although the rule will not be implemented until November 1, substantial work will be required before that date to prepare for its implementation. End-users, local distribution companies, and interstate pipelines will immediately commence work to modify the curtailment plans of the interstate pipelines in accordance with this rule and the NGPA.

In past curtailment proceedings the parties have often arrived at a settlement of all issues without resort to adjudicatory proceedings before the Commission. This procedure may be appropriate here, and nothing in the rule precludes any interstate pipeline and its customers from proposing, as a settlement, a curtailment plan that differs from that set out in our rule. Such a settlement will be evaluated by the Commission in the light of its responsibility to meet the statutory goal of protecting, to the maximum extent practicable, high priority users and essential agricultural uses.

Summary of Comments and of Revisions of Commission Rule

On January 12, 1979, the Commission issued its Notice of Proposed Rulemaking 44 FR 3725 (January 18, 1979) for development of a curtailment rule to implement Section 401 of the NGPA on a permanent basis. The proposed rule was issued prior to final action of ERA and USDA with respect to issuance of their final rules required by Section 401.[5] The Commission now has the benefit of the final ERA rule and the interim final USDA rule.

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[5] ERA's final rule was issued on March 9, 1979, and the Interim Final Rule of USDA was issued to become effective on February 28, 1979, until superseded by a permanent rule expected to be issued on or about April 30, 1979.

The Commission's final rule adopts the ERA rule in its entirety, and the Certification of "Essential Agricultural Use" and Volumetric Requirements of USDA's interim final rule. Interstate pipelines are required to provide gas to supply the certified volumetric requirements for those users designated by the USDA.[8] However, the interstate pipeline is not required to deliver natural gas to any customer in violation of any volumetric limitations set out in the contract between the interstate pipeline and its customer.

The Commission recognizes that incorporation by reference of the USDA rule will result in some expansion in the entitlements over the entitlements contained in current pipeline curtailment plans. In the past, the Commission's policy has not favored load growth; i.e., increasing new customers or base period entitlements. However, the Commission's reading of the NGPA and the many comments and legal analysis provided it in the extensive record in this proceeding leads it to the conclusion that some agricultural load growth was intended by Congress. The Commission has determined it must make the appropriate modifications where necessary to carry out the Congressional mandate. The Commission's reading of Section 401, amply supported by the rulemaking record, indicates that Congress intended to up-grade the priority classification of essential agricultural users while specifically protecting high-priority users. However, Congress did not mandate that high-priority load growth. Thus, to the extent that load growth is required by the USDA rule and the agricultural users (or its local distributor) has the requisite contractual authority, it is the Commission's view that Congress intended that agricultural load growth be permitted. The Commission recognizes that if gas supplies are inadequate this may require some disruption of service to established consumers but the legislative history indicates that Congress was prepared to accept such an impact.

The significance of the Commission's statement in the interim rule that pipelines are not required to serve those certified USDA volumetric requirements if serving them would require providing gas in excess of volumetric specifications in contracts or certificates of public convenience and necessity was a subject of much comment and discussion by the parties to this rulemaking. Some commentors took the position that Section 401 created new natural gas entitlements that override existing certificates or contracts. However, it was pointed out by many other parties that increased service by interstate pipelines is governed by Section 7 of the Natural Gas Act (NGA) dealing with certificates of public convenience and necessity while curtailment plans in contrast deal with reductions in existing service. Most of the speakers questioned at the hearings agreed that Section 401 of the NGPA does not compel an interstate pipeline to serve an essential agricultural user who is not now served by that pipeline. The view expressed was that absent the issuance of a certificate of public convenience and necessity under Section 7 of the NGA interstate pipelines cannot be required to increase service to existing customers or attach new customers. There was no indication that Congress, in enacting the NGPA intended to override the certificate requirements of Section 7 of the NGA. It was pointed out by a number of speakers including representatives of several state Commissions that the policies of local distribution companies regarding the addition of new customers is generally subject to state regulation. The Commission does not believe that Section 401 binds state regulators to order local distribution companies to add new customers, increase deliveries or execute new or modified contracts or service agreements.

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[8] The Department of Agriculture certified essential agricultural uses without regard to contract or service limitations.

In general, it is the Commission's view that contract and certificate limitations would apply whether or not the Commission made a specific reference to them in its regulation. The Federal Power Commission (FPC) in allocating diminished supplies of natural gas to users with existing contracts was required to override certain contract features but it was generally recognized that curtailment plans did not create additional contract entitlements.

In discussing the natural gas shortage and the need for curtailments, the United States Supreme Court stated:

> The shortage is said to require curtailment of contracted natural gas deliveries by Transco to its customers during periods of high demand. The curtailment plans concern methods of allocating the shortfall among the various customers. *FPC* v. *Transcontinental Gas Pipeline Corp.*, 423 U.S. 326, 327–8 (1976).

This statement indicates the Supreme Court's recognition, that curtailments are superimposed upon existing contractual relationships.

Similarly, in its initial discussion of the Transco curtailment case the United States Court of Appeals for the District of Columbia stated:

> When a pipeline company's natural gas supplies become inadequate to meet contractual commitments to customers, there must be a provision—through a curtailment plan—for apportioning the diminishing gas supply among the customers. *State of North Carolina* v. *FERC*, No. 76–2102 (D.C. Cir. 1978), slip opinion at 8.

The FPC's later curtailment plans did not recognize the contract distinction between firm and interruptible contracts. The underlying goal in the FPC's curtailment policy was to establish a system of priorities of service based on the end use of the natural gas. The firm interruptible contract distinction does not provide an adequate basis for determining the end use of the gas. In general, however, except where it was necessary to achieve end-use principles, curtailment policy has recognized that entitlement to gas requires both contractual authority as well as recognition in a curtailment plan.

The Commission adopts the USDA's certification of essential agricultural uses, but fully recognizes that increases in service are still subject to applicable state law, to Section 7 of the NGA, and, existing contracts to which the interstate pipeline is a party. Parties are free to amend their contracts and pipelines are free to file applications for new or amended certificates under Section 7.

In all other respects, it is the Commission's intention to preserve the existing base period data and method of implementation of existing interstate pipeline curtailment plans. We are particularly mindful of the Statement of Managers which expresses a clear desire to avoid disruption of existing curtailment plans upon implementation of Section 401.

Alternate Fuel Test

The Commission is authorized by Section 401(b) of the NGPA to exercise its authority to approve or modify certified volumes of all essential agricultural users through application of a statutory alternate fuel test. The Commission, under Docket No. RM79–40, is issuing today as a corollary rule, a Notice of Proposed Rulemaking which notices a rule providing for procedures for making the alternate fuel determination. Accordingly, those principles will not be addressed here.

Data Verification Committees

The concept of using a Data Verification Committee (DVC) in order to deal with data management problems on each pipeline as expressed in the Commission's proposed rule received considerable attention in the comments of the parties. The agricultural community strenuously objected to this use of the DVC. Agricultural representatives argued that the proposed rule would vest too much power in the DVC by virtue of giving them fact-finding authority. They also argued that agricultural representatives were not included as standing members. Many agricultural users stated that, rather than deal with a DVC, they would prefer to come directly before the Commission to resolve data problems.

The Commission in deference to the strong reservations of the agricultural community about DVC procedures, and to questions whether the Commission could lawfully delegate its authority to a DVC, has determined that it will not utilize these committees in a fact-finding mode.

However, the Commission believes that the record indicates that the DVC's would be useful in a more limited capacity than in the proposed rule. There is a need to insure that all data are expressed in a consistent fashion and that data be reviewed for mechanical and reporting errors. There is also a need for a forum which would permit exchanging data and information among the various pipeline customers affected by a pipeline curtailment plan. Finally there is a need to discuss matters in controversy so that all parties and the Commission can understand the issues that the Commission must address. The Commission believes that the DVC's can perform these limited functions in a legally appropriate fashion and in a way that will assist and not prejudice any customer in obtaining its legal entitlements.

Attribution

The rule promulgated provides an attribution mechanism so that agricultural users, local distribution companies, and interstate pipelines that receive gas from more than one source can allocate their priority needs of natural gas among those sources.

The permanent rule re-orders the priority classifications of pipelines' existing curtailment plans. The Commission believes high priority and essential agricultural requirements should be attributed among suppliers based on the underlying curtailment plans of the interstate pipeline suppliers. Accordingly, the requirements will be attributed to a particular direct supplier based on a fraction equal to the entitlements from that supplier divided by total supplies from all sources, including non-pipeline supplies. An essential agricultural user or local distribution company with supply sources which supplemented interstate pipeline supplies, during the base period of the pipeline's curtailment plan would not be attributed to interstate pipeline suppliers.

Storage

The revised curtailment priorities embodied in the ERA rule seeks to protect customer storage injection.

Section-by-Section Summary of the Final Rule

The following is a section-by-section summary of the Commission's final rule.

Purpose (§ 281.201)

This section states that it is the purpose of this subpart to provide effective November 1, 1979, that the curtailment plans of interstate pipelines protect, to the maximum extent practicable, deliveries of natural gas for essential agricultural uses and high priority uses.

Applicability (§ 281.202)

The subpart applies to the following interstate pipelines:

Alabama-Tennessee Pipeline Company
Algonquin Gas Transmission Company.
Arkansas Louisiana Natural Gas Company.
Cities Service Gas Company.
Colorado Interstate Gas Company.
Columbia Gas Transmission Corporation.
Consolidated Gas Supply Corporation.
East Tennessee Natural Gas Company.
Eastern Shore Natural Gas Company.
El Paso Natural Gas Company.
Florida Gas Transmission Company.
Great Lakes Gas Transmission Company.
Inter-City Minnesota Pipelines, Ltd., Inc.
Kansas-Nebraska Natural Gas Company, Inc.
Lawrenceburg Gas Transmission Company.
Michigan-Wisconsin Pipeline Company.
Mid-Louisiana Gas Company.
Midwestern Gas Transmission Company.
Mississippi River Transmission Company.

Montana Dakota Utilities Company.
National Fuel Gas Supply Company.
North Penn Gas Company.
Northern Natural Gas Company.
Northwest Pipeline Corporation.
Panhandle Eastern Pipeline Company.
South Georgia Natural Gas Company.
Southern Natural Gas Company.
Southwest Gas Corporation.
Tennessee Gas Pipeline Company, a Division of Tenneco, Inc.
Tennessee Natural Gas Lines.
Texas Eastern Transmission Corporation.
Texas Gas Transmission Corporation.
The Inland Gas Company.
Transcontinental Gas Pipeline Corporation.
Transwestern Pipeline Company.
Trunkline Gas Company.
United Gas Pipe Line Company.
Western Gas Interstate Company.

Definitions (§ 281.203)

This section defines the following terms as they are used in this subpart:

"Currently effective curtailment plan" means the plan for natural gas curtailment which an interstate pipeline had in effect on March 1, 1979;

"Direct sale customer" means an essential agricultural user that purchases natural gas directly from an interstate pipeline and consumes such natural gas for an essential agricultural use;

"Essential agricultural use" means any use of natural gas, certified by the Secretary of Agriculture as such a use under section 401(c) of the NGPA, as identified in 7 CFR 2900 *et seq.*;

"End-use curtailment plan" means a tariff provision that requires that, if there is a supply shortage, curtailment of natural gas deliveries will be based on end-use factors;

"Indirect sale customer" of an interstate pipeline means an essential agricultural end-user served by a local distribution company which is served directly or indirectly by an interstate pipeline;

"High-priority user" means a person who uses natural gas in a residence, a small commercial establishment, a school or hospital, or for police and fire protection, sanitation or correctional facilities;

"Local distribution company" means a local distribution company served directly by an interstate pipeline.

This section also defines alternate fuel; entitlements; rolling base period; residence; small commercial establishment; hospital; and school.

Section 281.203(b) provides for cross-references which are essential agricultural requirements, and index of entitlements.

Tariff Filing Requirements (§ 281.204)

Paragraph 281.204(a) states that an interstate pipeline must file tariff sheets which provide that natural gas will be delivered in accordance with provisions of this subpart. If the pipeline has no curtailment plan, it must file a tariff which includes one that complies with this subpart by October 1, 1979. If the pipeline has curtailment provisions in its currently effective tariff, it shall file amendments to that tariff reflecting a curtailment plan which complies with this subpart no later than October 1, 1979. The effective date of all such tariffs will be November 1, 1979.

Paragraph 281.204(b) states that the index of entitlements for an interstate pipeline with an end-use curtailment plan shall identify the natural gas entitlements in each priority of service category (determined under § 281.205(a)) for each direct sale customer, each local distribution company, and each interstate pipeline purchaser. The indices of entitlements will be periodically updated. For curtailment plans using a fixed base period, new indices reflecting changes in Priority 2 entitlements are due each October 1st for a proposed effective date of November 1st. For plans now using a rolling base period, annual updates in Priority 2 index of entitlements must be filed when other end-uses are updated in accordance with currently effective tariffs. Other amendments to the indices must be made if the Commission determines, under Subpart C, that essential agricultural user has an alternative fuel availability for Priority 2 entitlements, and removes that essential agricultural use from Priority 2 and places it in the appropriate curtailment category.

Each tariff shall contain provisions that require interstate pipelines to provide for delivery of enough gas to respond to emergency situations during periods of curtailment in order to forestall irreparable injury to life, property or for minimum plant protection during shut-downs (§ 281.204(c)).

The delivery requirements of this subpart will not exceed the volumetric requirements of the contract between a pipeline and its customer.

General Rule (§ 281.205)

Paragraph 281.205(a) requires interstate pipelines to establish a high-priority use category designated as Priority 1 and an essential agricultural use category designated as Priority 2. Priority 1 shall include all high-priority use entitlements of direct and indirect customers and related storage injection volumes. Priority 2 shall include all essential agricultural use entitlements of its direct and indirect customers and related storage injection volumes.

The method of curtailment for end-use curtailment plans requires that deliveries of natural gas be curtailed sequentially beginning with the lowest priority of service category. All categories must be fully curtailed before Priorities 1 and 2 are curtailed. Priority 1 shall be curtailed last (§ 281.205(b)(1)). Subparagraph 281.205(b)(2) requires that all priority categories in existing plans be placed below new categories 1 and 2. Entitlements in existing categories must be reduced to the extent that entitlements have been placed in categories 1 and 2.

Paragraph 281.205(c) requires an interstate pipeline to classify customer storage injection gas in the same manner as in the curtailment plans in effect on March 1, 1979. If gas volumes for storage are classified by end-use, the pipeline must recalculate volumes for each priority category according to the index of entitlements. Otherwise, no storage injection volumes may be recalculated, reclassified or included as Priority 1 or 2 entitlements.

The calculation of entitlements in priority of service categories shall be computed in the following manner: for Priority 1 in accordance with § 281.206; for Priority 2 in accordance with § 281.207. Each interstate pipeline with an end-use curtailment plan shall reduce entitlements to all other categories of service to the extent those entitlements have been placed in Priority 1 or 2.

Classification of Priority 1 Entitlements (§ 281.206)

Paragraph (a) of this section defines "high-priority entitlements" as the volume of gas a person (direct sale customer, local distribution company or interstate pipeline purchaser) is entitled to receive under the current curtailment plans of the particular interstate pipeline on account of its own high-priority uses and also (in the case of a local distribution company or the pipeline itself) those of its customers. A pipeline is entitled to receive gas for its own high-priority uses and the high-priority uses attributed by direct sale customers and local distribution company customers to the pipeline as a source of that gas.

Paragraph 281.206(b) states that local distribution company customers and direct sale customers may request each of its direct interstate pipeline suppliers to classify as Priority 1 entitlements natural gas that either entity is entitled to purchase for its high-priority uses.

The customer must designate the entitlements in each priority of service category in the current curtailment plan for which Priority 1 reclassification is requested and request that these entitlements be removed from categories of service in the currently effective curtailment plan.

An interstate pipeline must reclassify high-priority entitlements as requested and must reduce by an equal amount the entitlements in the priority of service categories designated by the direct sale customer or local distribution company.

Paragraph 281.206(c) prescribes the same procedure for interstate pipeline purchasers which request reclassification of high-priority entitlements from interstate pipeline suppliers. The interstate pipeline purchaser shall designate these high-priority entitlements and request that those entitlements be removed from other categories of service. These high-priority entitlements are equal to the attributed Priority 1 entitlements calculated under section 281.209.

Classification of Priority 2 Entitlements (§ 281.207)

Paragraph 281.207(a)(1) states that direct sales customers may request Priority 2 classification for their essential agricultural uses (calculated under section 281.208) from direct interstate pipeline suppliers. Under subparagraph (a)(2), the essential agricultural users must designate the entitlements in the priority of service categories of existing plans and request their removal. The pipeline will then reclassify essential agricultural use requirements as Priority 2 entitlements and accordingly reduce entitlements in other priority of service categories as the customer designates.

Under paragraph (b), an indirect sale customer which is an essential agricultural user may request that its local distribution company which supplies the customer directly ask the pipeline supplier to reclassify the customers indirect essential agricultural requirements as Priority 2 entitlements.

Paragraph (c) states that a local distribution company must attribute the indirect essential agricultural requirements for which reclassification is sought by indirect sale customers to direct interstate pipeline suppliers, in accordance with § 281.209. Local distribution companies must request direct interstate pipeline suppliers to classify indirect essential agricultural requirements as Priority 2 entitlements. Under subparagraph (c)(2), the entitlements designated by the local distribution company to reflect attributed indirect essential agricultural requirements are removed from the category of service in which they are found in existing curtailment plans. The interstate pipeline shall reclassify the indirect essential agricultural requirement as a Priority 2 entitlement and reduce the entitlements of the local distribution company in other categories as designated.

An interstate pipeline purchaser, under § 281.207(d) may request each of its direct interstate pipeline suppliers to classify the attributable indirect essential agricultural requirements as Priority 2 entitlements in the currently effective curtailment plan of the supplier.

Under subparagraphs 281.207(d)(2) and (3), the interstate pipeline purchaser will designate the entitlements in the current plan of the supplier and request their removal from the existing priority of service category. The supplier shall then classify the attributed Priority 2 entitlements as Priority 2 entitlements and reduce the current priority of service categories as designated by the purchaser.

Calculation of essential agricultural requirements and attributable Priority 2 entitlements (§ 281.208)

The total essential agricultural requirement of an end-user will be the volumes certified by the Secretary of Agriculture and calculated in acordance with 7 C.F.R. § 2900.4 and reduced to the extent of any alternate fuel determination in accordance with subpart C under Section 401(b) of the NGPA. These volumes shall be calculated on a daily, monthly and seasonal basis. The direct essential agricultural requirement is that part of the total requirement attributable under § 281.209 to the direct interstate pipeline supplier. The indirect essential agricultural requirement is that portion attributable to a direct local distribution company supplier.

Under § 281.208, paragraph (b) prescribes how the essential agricultural user calculates its total, direct and indirect essential agricultural requirements. An essential agricultural user will compute current requirements as they are designated by the Secretary of Agriculture in accordance with Title 7 of the Code of Federal Regulations,

§ 2900.4, minus any volumes determined by the Commission as replaceable by an alternate fuel. As used in 7 C.F.R. Part 2900, current requirements means the energy used during the most recent 12 months for which there is a record or the maximum volume which a user could consume presently for essential agricultural uses. Paragraph (c) states that the local distribution companies calculate attributable indirect essential agricultural requirements for its end-user customers by dividing their customers' essential agricultural requirements among the companies' direct pipeline suppliers. Interstate pipeline purchasers calculate attributable Priority 2 entitlements under paragraph (d) by attributing Priority 2 entitlements in each purchaser's index of entitlements among that purchaser's direct interstate pipeline suppliers.

Attribution (§ 281.209)

Section 281.209 sets forth the rules for attributing total essential agricultural requirements by an essential agricultural user, indirect essential agricultural requirements of an essential agricultural user by its local distribution company supplier, and Priority 1 and 2 entitlements by an interstate pipeline. This section is inapplicable to any end-user or distribution company which has only one source of gas and to any pipeline which does not receive gas from another pipeline.

Natural gas from all direct sources shall be included in the computations for purposes of attribution.

However, if an essential agricultural user attributes any part of its essential agricultural requirements to a source other than a direct supplier as defined in paragraph (c) (for example, synthetic natural gas facilities or independent producers), the user may not seek reclassification to Priority 2 for that gas. Similarly, a local distributor may not seek Priority 2 for any part of its indirect essential agricultural requirements attributed to a source other than a direct supplier. And an interstate pipeline purchaser may not seek Priority 1 or 2 reclassification for any part of the Priority 1 or 2 volumes to which it is entitled which are attributed to a source other than a direct supplier.

Essential agricultural user

Under paragraph 281.209(d) an essential agricultural user must compute its requirements attributable to one direct supplier by multiplying total essential agricultural requirements by the annual quantity entitlement from said supplier, then dividing the result by the total volume of gas received from all sources during the base period of the direct supplier's current curtailment plan. Operative definitions are found in paragraph (c). If the user lacks entitlement with only one of its suppliers, the requirement attributed to that supplier is that part of the user's total essential agricultural requirements not attributed elsewhere. When a user lacks entitlements with more than one supplier the essential agricultural requirements attributable to any one supplier is found by multiplying the unattributed portion of the total requirements by the volume of gas received in 1972 from that supplier, and dividing the result by total 1972 supplies received.

Local distribution companies

Under paragraph 281.208(e), a local distribution company calculates its indirect essential agricultural requirements attributable to a direct supplier by multiplying those requirements by the annual quantity entitlements from the supplier and dividing the result by the total volume of gas received from all sources during the base period of the fixed period in the current curtailment plan of the supplier used to establish a customer's entitlements.

Interstate pipelines

An interstate pipeline will attribute Priority 1 and 2 entitlements respectively to a direct supplier according to paragraph (e) by multiplying total Priority 1 and 2 entitlements respectively by the annual quantity entitlements from the supplier and dividing the product by the total volume of gas received from all sources during the base period of the supplier's current curtailment plan.

Conflicting Data (§ 281.210)

Under paragraph (a) an interstate pipeline may not include in its index of entitlements under Priorities 1 or 2 any volumes requested to be so classified, if any information in the records of the pipeline differs from request for reclassification of Priority 1 or 2 entitlements. Under paragraph (b) a local distribution company is prohibited from seeking classification of volumes as requested if similar discrepancies arise between its records and the request of an essential agricultural user.

Filing and Documentation (§ 281.211)

Priority 1

Under subparagraph (a)(1), the requests for reclassification of high-priority entitlements to Priority 1 entitlements made by direct sale customers and local distribution companies must be submitted in writing by June 15, 1979, and accompanied by tables showing both high-priority entitlements and the end-users of the gas in the priority of service category being reclassified and the end-use data used to establish high-priority requirements and the designated end-use of the natural gas.

Subparagraph (a)(2) sets July 15, 1979 as the deadline for written requests by interstate pipeline purchasers to request that their pipeline supplier's reclassify high-priority requirements in currently effective curtailment plans as Priority 1 entitlements. Such requests must be accompanied by tables of high-priority entitlements and end-uses in each category of the supplier's plans for which reclassification is requested, copies of end-use data used to establish high-priority requirements, and a table indicating volumes and priority of service categories for which the purchaser's customers sought reclassification.

Priority 2

Under subparagraph (b)(1), essential agricultural users requesting that local distribution companies or direct interstate pipeline suppliers classify essential agricultural requirements to Priority 2 entitlements must do so in writing no later than June 15, 1979 and include a sworn statement which includes the volumes and end-use of gas requested to be made Priority 2, the SIC Code activities of the user, data and calculations used to determine essential agricultural requirements under USDA regulations (7 CFR § 2900.4) and a copy of a users petition for an alternate fuel determination for any boiler fuel facility, if appropriate.

Paragraph (b)(2) establishes June 30, 1979 as the deadline for written requests by local distribution companies to direct interstate pipeline suppliers requesting Priority 2 classification. Such requests must contain appropriate calculations and copies of all requests received from the particular company's essential agricultural user customers.

Interstate pipeline purchasers must request from suppliers classification of attributable Priority 2 entitlements as Priority 2 entitlements no later than July 15, 1979 and in writing, according to subparagraph (3). Appropriate calculations and copies of customer requests must accompany the request.

Subparagraph (4) states that the data required under paragraph (b) must be filed in years after 1979 only if a change in Priority 2 is sought. The deadline dates will continue to be applicable except for any interstate pipeline with a rolling base period.

Draft Tariff Sheets and Index of Entitlements (§ 281.212)

This section requires that each interstate pipeline prepare draft tariff sheets and a draft index of entitlements in accordance with this regulation and serve these documents on all customers and, together with all § 281.210 documents, on the Data Verification Committee no later than August 1, 1979. The same deadline holds true for subsequent years, except for pipelines with a rolling base period which are permitted to prescribe an appropriate date.

Data Verification Committee (§ 281.213)

Paragraph (a) requires, at a minimum, that the Data Verification Committees be composed of a representative of the interstate pipeline, of the Commission staff, both a large and small local distribution company, and an essential agricultural user. State and local regulatory bodies and a representative of the Department of Agriculture may be members at their option.

The Committees will receive all calculations behind the draft tariff sheets and the proposed index of entitlements. Any information requested by the Committee shall be supplied by the interstate pipeline.

Under paragraph (c) any customer of an interstate pipeline may file a written protest concerning the index of entitlements. The protests shall be filed by August 24, 1979.

Paragraph (e) provides that the Committee shall prepare a report concerning the draft tariff sheets and shall, at least, specify arithmetic errors, and prepare an evaluation of all protests. Such report shall be submitted to the interstate pipeline no later than September 23, 1979.

Notice, complaint and remedy (281.214)

Any direct sale customer or local distribution company aggrieved by an alleged violation of this rule shall file complaint in accordance with 18 CFR 1.6 within 45 days of notice.

If a violation is found by the Commission, it shall take whatever action it deems appropriate.

Additional relief (§ 281.215)

Upon rejection of a request for Priority 1 or 2 classification under § 281.206 or otherwise, or the failure of a local distributing company to request reclassification on behalf of an end-user, for any reason, the aggrieved party may file a request for relief from curtailment which conforms with Commission regulations in 18 CFR 1.7. The request shall contain the information required in 18 CFR 2.78(b).

(Natural Gas Act, as amended, 15 U.S.C. 717 *et. seq.;* Public Utility Regulatory Policies Act of 1978, Pub. L. 95-617; Natural Gas Policy Act of 1978, Pub. L. 95-621; 92 Stat. 3350; Department of Energy Organization Act, P.L. 95-91; E.O. 12009, 42 FR 46267)

In consideration of the foregoing Part 281, Subpart B, Subchapter I, Chapter 1, Code of Federal Regulations is amended effective June 7, 1979, as set forth below.

By Order of the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,054]

44 F. R. 30323 (May 25, 1979)

[18 CFR Parts 3 and 284]

[Docket No. RM79-34]

Transportation Certificates for Natural Gas for the Displacement of Fuel Oil

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission gives notice that, for the purpose of displacing fuel oil, it hereby issues special rules authorizing the transportation of natural gas purchased by certain end-users. This rule was initiated by the March 19, 1979, proposal of the Economic Regulatory Administration of the Department of Energy. It serves to further the objective of displacing fuel oil with natural gas so that the nation's current shortage of certain crude oil products may be minimized.

DATE: Effective May 17, 1979.

FOR FURTHER INFORMATION CONTACT: Robert Platt, Office of the General Counsel, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 275-0161 or James Kiely, Office of Pipeline and Producer Regulation, 825 North Capitol

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(202) 275-4384.

I. Introduction

On March 19, 1979 the Economic Regulatory Administration (ERA) of the Department of Energy proposed a rulemaking to the Commission pursuant to section 403(a) of the DOE Organization Act, 42 U.S.C. 7173(a). The ERA proposed rule[1] would establish a procedure for the issuance of one year certificates of public convenience and necessity under Section 7(c) of the Natural Gas Act, 15 U.S.C. 717f(c), authorizing the transportation of natural gas purchased by end-users in order to displace fuel oil. On April 2, 1979, the ERA established a procedure to certify the eligibility of end-users for this program.[2] The Commission provided a written comment procedure on the ERA proposed rule, and held a public hearing in Washington, D.C. on April 30, 1979.[3] The ERA proposed rule was presented by John F. O'Leary, Deputy Secretary of Energy. Comments on the ERA proposed rule were received from Senator Howard Metzenbaum, as well as pipelines, consumer groups and end-users.

II. Related Fuel Oil Displacement Programs

Several existing functions within the Commission's jurisdiction will assist in displacing fuel oil with natural gas. The most important method of reducing fuel oil consumption will be by reducing (or halting any further deterioration of) curtailment levels on interstate pipelines. The objective of maximizing interstate pipeline supplies was advanced by Secretary of Energy James R. Schlesinger:

> The Department will undertake two approaches to reduce imports in the near-term through movement of surplus gas to oil users. The first approach is to encourage sales from producers or intrastate pipelines to interstate pipelines and distribution companies. Such sales will increase general system supply, thereby reducing overall gas curtailments and displacing fuel oil. The second approach is to encourage and facilitate the transportation of natural gas purchased directly from producers or intrastate pipelines by users capable of substituting gas for oil. In general, the Department's first priority is to encourage additions to interstate pipeline system supplies. However, when surplus gas is not fully utilized by interstate pipelines, the transportation of direct purchases will be facilitated.[4]

The Commission believes that the Secretary is correct in giving first priority to encouraging additions to interstate system supplies; direct sales to users capable of substituting fuel oil for natural gas generally must yield to calls on available gas by customers served from system supply. Our actions in the rulemaking are intended to fit the fuel oil displacement program to that order of priorities.[5]

Congressional enactment of the Natural Gas Policy Act of 1978 was motivated by a perceived need to improve the supply condition of interstate pipelines. The key feature of the NGPA was the elimination of the artificial distinction between the interstate and intrastate natural gas markets. Congress believed that such a merger in conjunction with the provisions of Title I, which provides incentive prices to natural gas producers in excess of cost-based prices under the Natural Gas Act, should, over time, cause additional natural gas to become available. In addition, the provisions of Title III of the NGPA, particularly sections 311 and 312, seek to make any intrastate surplus deliverability available to interstate pipelines and local distribution companies. Hence, the Commission is under a clear mandate from the Congress to assist in increasing interstate system supplies. Therefore the first and most appropriate means of displacing fuel oil consumption is to increase interstate system supplies in order to reduce curtailments and thereby generally to reduce fuel oil requirements.

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[1] 44 FR 17644 (March 22, 1979).

[2] 10 CFR Part 595, 44 FR 20368 (April 5, 1979).

[3] Order Commencing Rulemaking, 44 FR 21682 (April 11, 1979).

[4] Statement dated March 13, 1979 at 2. See also Transcript at 33.

[5] Direct purchases of natural gas have a role within a fuel oil displacement initiative because they permit natural gas to be targeted to those users or facilities using high-cost, high quality petroleum fuels. Allocating all available gas as system supply through normal curtailment plans may, in some instances, result in displacing low quality residual fuel oil or other natural gas substitutes so that the fuel oil displacement program would not produce optimal impact.

Second, the recently promulgated direct sales program in Subpart E of Part 157 permits schools, hospitals, and essential agricultural users to displace fuel oil.[6]

Third, the Commission intends to clarify 18 CFR 2.79 to permit process and feedstock users to participate in fuel oil displacement. At present, some process and feedstock users which receive direct sale gas under FPC Order No. 533 and FERC Order No. 2 may not be eligible to also use system supply gas in boilers, even if the pipeline supplying the user is not in curtailment. A future clarification of 18 CFR 2.79 may be appropriate to permit such boiler fuel use to displace additional fuel oil.

III. The Fuel Use Act

On May 8, 1979, the Powerplant and Industrial Fuel Use Act of 1978 (PIFUA), Pub. L. 95-620, became effective. Section 301 of PIFUA prohibits the use of natural gas as a primary energy source in powerplants to the extent that such use exceeds historic use. In addition, the Secretary of Energy may prohibit other uses of natural gas by either powerplants or major fuel burning installations.

There is general agreement that the long term solution to the nation's energy needs relies upon more abundant fuels such as coal, solar and other renewable energy sources rather than oil or natural gas.[7] The ERA rule, therefore, appears to be in conflict with accepted energy policy objectives. However, the ERA argues that in the short run, considering the fuel oil situation and the reported additional availability of natural gas, natural gas is currently the more appropriate fuel for facilities capable of burning either natural gas or fuel oil. We do not consider the ERA proposal to be inconsistent with our nation's general policies to encourage the use of more abundant fuels in place of natural gas if the displacement program is clearly articulated to be of short-term duration and tied to current and critical fuel oil shortages.

The Commission notes that the authority to grant any exemption from PIFUA resides in the Secretary of Energy and not with this Commission. To the extent of our authority, the Commission will further the purposes of Title I of PIFUA. In the instant rule, all fuel oil displacement transactions are conditioned upon full compliance with the PIFUA.

IV. Policy Considerations

The final rule is an attempt to balance a number of competing policy considerations. On the one hand, the nation must remedy a serious and immediate fuel oil supply situation. On the other hand, both statutory and policy constraints limit the ways in which natural gas can be made available to fuel oil users.

Middle distillate fuel oil is in critically short supply. Middle distillate fuel oil consists primarily of home heating oil and diesel fuel. Accordingly, many residential, commercial and small industrial fuel oil customers will be particularly affected by high-priced and possibly inadequate distillate fuel oil. It is this Commission's responsibility to afford these users, who would be considered "high priority" if served by natural gas,[8] relief within our discretion so long as this relief does not come at the expense of other high priority users.

Distillate oil stocks are currently about 117 million barrels. This is significantly below minimum acceptable levels for this time of year, and 17 million barrels, or 14.6%, below the level at this time in 1978.[9] In order to achieve historically acceptable levels of distillate supply by the onset of next winter's heating season, the Department of Energy estimates it will be necessary to increase stocks by one million barrels per day. This goal will be extremely difficult to achieve because domestic refiners have rarely produced distillate at a rate that would allow for such a rapid build-up. The primary near-term alternative measures for accelerating distillate stock are to: (1) Increase imports; (2) reduce gasoline production in order to permit refiners to increase distillate production; (3) increase conservation; and (4) displace distillate use with competing fuels, particularly natural gas.[10]

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[6] Order No. 27, 44 FR 24825 (April 27, 1979).

[7] Statement of James R. Schlesinger dated March 13, 1979 at 1.

[8] Transcript at 19; Comments of Tennessee Gas Pipeline Company, filed May 4, 1979.

Each option presents its own potential disadvantages. Increased reliance upon imported distillate oil is not only dangerous, given the insecurity of foreign crude oil and petroleum product supplies, but could also tighten foreign petroleum product markets, and significantly increase the consumer cost of distillate oil next winter.

Reducing gasoline production in order to maximize refinery yields of distillate oil presents other difficulties. Induced shortages of gasoline could create serious dislocation in the transportation sector of our economy because of its virtually total dependence upon liquid hydrocarbons. If other potentially effective means of increasing distillate supplies are seen to exist without equivalent risks or harm to the public welfare they should be fully utilized. The public interest lies in a balanced set of strategies and actions for coping with the fuel emergency.

Increased conservation measures are in the public interest, and must be a part of any strategy for dealing with fuels shortages. But additional near term conservation measures are limited in number and impact. There simply does not appear to be a capability to meet this winter's distillate stock level objectives through increased conservation.

Displacing fuel oil with natural gas also presents difficulty. The Commission is concerned that such a program will be mistaken for a change in long-term end-use policy, which it is not. The Commission is also concerned that the fuel oil displacement program will increase deliveries to low priority users now but at the expense of higher priority users later on. However, this problem of user equity can be addressed and resolved by making fuel oil displacement sales of relatively short-term duration, and, even then, subject to interruption if high priority natural gas needs are not being met. The danger of harm to high priority natural gas users can be further mitigated by targeting the program to sales of natural gas not currently committed or dedicated to the interstate market.

Accordingly, we believe that the Commission's responsibility to high priority customers, regardless of the type of fuel consumed, compels our action. The acceptable level of risk associated with the natural gas displacement option leads us to conclude that such transactions, properly conditioned, are in the public interest.

The NGPA creates both opportunities for and constraints upon a fuel oil displacement program. Natural gas supplies available for this program are increased by the NGPA section 311(b) which permits interstate pipelines and local distribution companies served by interstate pipelines to acquire surplus natural gas from the intrastate market at prices based upon the selling intrastate pipeline's weighted average cost of gas. These section 311(b) supplies are particularly important to small, high-priority users which cannot participate in direct sale programs. But insofar as there may exist a temporary surplus of natural gas resulting from the recent energy legislation, it should be made accessible not only to high-priority users served by interstate system supplies, but also to those users who can contribute to the nation's short-term fuel oil displacement needs.

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[9] Weekly Petroleum Status Report, U.S. Department of Energy, May 11, 1979.

[10] Transcript at 20; Further Comments of the Department of Energy, filed May 7, 1979 at 2-3.

This rule balances the interests of these two user categories. The design objective of this rule is to give eligible fuel oil users access to available natural gas without providing them any advantage over those who rely upon interstate system supplies to meet their high-priority requirements. For example, NGPA section 311(b) price limitations are placed upon fuel oil displacement transactions, if the seller is an intrastate pipeline. Such a price limitation will place fuel oil using direct purchasers in the same position as interstate pipelines and local distribution companies served by interstate pipelines with respect to access to surplus intrastate natural gas under NGPA section 311(b) programs.

In addition to price considerations, the Commission will monitor the fuel oil displacement program to prevent any serious disruption of markets, to maximize the efficient use of the interstate pipeline transportation network, and to coordinate the program with pipeline curtailment policies.

V. Section by Section Summary

§ *284.200 Applicability*

Section 284.200 emphasizes that the purpose of this program is the displacement of fuel oil consumption. The fuel oil displacement transactions are implemented under both section 311(a)(1) of the NGPA and section 7(c) of the Natural Gas Act.

§ *284.201 Definitions*

Section 284.201 provides definitions for this subpart. Eligible uses are determined by the Administrator of the Economic Regulatory Administration. The ERA has already established procedures for certifying eligible uses in 10 CFR 595.03. Although the Commission's transportation authorization is self-implementing in some instances, a condition to such transportation is the prior certification by the Administrator of the ERA that the use for which the natural gas is to be transported is an eligible use.

Several comments question whether the implementation of this program will in fact result in such displacement of fuel oil as to ameliorate the current supply shortage. The ERA has taken the position that displacement of any fuel oil by natural gas will assist the current supply situation. Although ERA may further refine its certification procedure to include additional requirements, such as restrictions of the program to particular geographical regions or type of fuel oil use, the Commission will accept any currently valid certification by the ERA when implementing this emergency program.

The definition of "volumes attributable to local supply" in § 284.201(g) is constructed to prevent the diversion of interstate system supplies from high-priority users served by a local distribution company making sales under this program. The definition of "interstate system supplies" in § 284.201(f) is broader than the committed or dedicated test proposed by the ERA. The term "system supplies" in paragraph (f)(1) includes all natural gas purchased by an interstate pipeline for resale to its on-system customers regardless of when the natural gas was committed under a contract. Natural gas purchased under Subpart C of Part 157 for assignment to a specific customer is an example of natural gas not within the scope of the definition.

As noted in Part IV above, the Final Rule reflects the Commission's concern for the current emergency conditions confronting high-priority fuel oil users. The Commission believes that such a supply condition will exist at least through the 1979–80 heating season. At this time, the Commission is unable to conclude that this program will be necessary beyond June 1, 1980. As a result, the Commission finds the period through June 1, 1980 to be a "fuel shortage emergency period."

§ *284.202 Interstate pipeline transportation authorizations.*

Section 284.202 authorizes the transportation by interstate pipelines of certain transactions on a self-implementing basis.

Section 284.202(a)(1) authorizes interstate pipeline transportation of direct sales by natural gas producers and other persons making first sales as defined in NGPA Section 2(21) without requiring that they obtain prior Commission approval under section 7(c) of the Natural Gas Act.

If the eligible user purchases gas directly from a producer, such gas is a first sale and subject to price ceilings under Title I of the NGPA. Additionally, only gas which was not "committed or dedicated to interstate commerce" within the meaning of section 2(18) of the NGPA is eligible to be transported under this section. The transportation of only natural gas meeting these conditions is exempted from the requirements of section 7 since the public interest would not be further served by requiring the issuance of a certificate. In order to make covered transportation of such natural gas authorized a self-implementing basis, the Commission is exercising its exemptive authority under section 7(c)(1)(B) of the Natural Gas Act. As explained in Part IV above, the ERA finds the current fuel oil situation an emergency of a magnitude to justify the issuance of temporary certificates. The Commission accepts the ERA emergency finding as equally applicable to the exemption provided in § 254.202(a)(1).

Gas currently available to the interstate system may not be diverted from that market under this exemption. Any proposed sale of interstate system supply under this program may be transported only if a certificate is granted under § 284.202(a)(3) and § 284.206. Transportation of natural gas under this section is subject to certain reporting requirements described in § 284.207.

The statutory authority for permitting an interstate pipeline to transport natural gas sold by an intrastate pipeline or a local distribution company under this program without first obtaining a section 7(c) certificate is section 311(a)(1) of the NGPA. This latter statutory provision states that the Commission may, by rule or order, authorize interstate pipelines to transport natural gas on behalf of intrastate pipelines or local distribution companies. In implementing this section initially in Part 284, Subpart A, the Commission focused primarily upon transportation of volumes destined for system supply. In developing the current rule, the Commission recognized that the need to develop a truly national transportation system pertains not only to the transportation of system supplies but also to the interstate transportation of natural gas owned by a particular end-user. The Commission believes that it should exercise its discretion under section 311 to permit the efficient and timely transportation of natural gas destined to serve a use found to be in the national interest and necessary to help manage the nation's fuels supply problems.

The Commission did not exercise the full breadth of its legal authority under NGPA section 311(a) and did not rely upon this broad interpretation of "on behalf of" in its authorizations under Subparts A and B of Part 284. Subpart F makes clear that transportation of direct sale gas to end-users was not included within the scope of the Subparts A and B authorizations. The Commission intends to further clarify Subparts A and B in the course of promulgating final rules in Docket No. RM79-3. These subparts may not be utilized to transport natural gas owned by an end-user.

Subpart F of Part 284 must be utilized if certain end-users wish to have qualifying natural gas supplies transported on a self-executing basis. Transportation of other types of natural gas supplies require section 7(c) authority as provided elsewhere in Subpart F.

Authorization for interstate pipeline transportation of direct sales by interstate pipelines is not self-executing. Section 284.202(a)(3) requires interstate pipelines to obtain Natural Gas Act section 7(c) authorization for the transportation of natural gas sold directly by interstate pipelines or an other persons not covered by §§ 284.202(a)(1) or (a)(2). The requirement for prior certification, while requiring additional time, is necessary to assure that the ability of interstate pipelines to purchase general system supply is not prejudiced in favor of direct purchases.

In keeping with the Commission's practices in its other direct sales programs, no Commission authorizations will be required for any incidental transportation performed by local distribution companies.[11]

Interstate pipelines may sell gas to fuel oil users if the gas is in excess of the current demands of the pipeline. As noted above, the Department of Energy's first priority for displacing fuel oil is the lowering of curtailment levels on interstate pipelines. However, local or regional surpluses may exist, and natural gas from interstate pipelines serving such areas could be made available to fuel oil users. The Commission must, however, review these instances on a case-by-case basis in order to adequately protect customers served by interstate system supplies.

Therefore, the transportation of such surpluses will be permitted only under certificates issued by the Commission on a case-by-case basis pursuant to section 7(c) of the Natural Gas Act. Application requirements for interstate pipelines are set forth in § 284.208. All transportation under this subpart, whether authorized under NGPA section 311(a)(1) or under Natural Gas Act Section 7(c), is subject to the conditions of this subpart.

Under § 284.202(b)(1), intrastate pipelines may sell gas to fuel oil users at a price which does not exceed the NGPA section 311(b) price. Special reporting requirements for such transactions are set forth in § 284.207(b).

Because the sale between the intrastate pipeline and the fuel oil user is a direct sale rather than a sale for resale, no sales authorization is required by NGPA sections 311(b) or 312(a) or Natural Gas Act section 7(c).

Under § 284.202(b)(2), a local distribution company, served by either an intrastate pipeline or an interstate pipeline, may sell natural gas to a fuel oil user. The local distribution company may sell on a self-executing basis only natural gas which represents volumes attributable to local supplies and not attributable to either deliveries from interstate pipelines or producers selling gas which was "committed or dedicated to interstate commerce" within the meaning of section 2(18) of the NGPA. While there is no price ceiling imposed upon these sales, state regulatory agencies have primary jurisdiction over the prices charged by local distribution companies. We note, also, that the sale price between the local distribution company and the fuel oil user will be determined by arms-length negotiation. The selling local distribution company will be competing against other sellers who are subject to price controls. Such sales of surplus local supplies by local distribution companies permit the distribution of certain costs such as take-or-pay obligations or SNG facilities across a greater number of customers.

Section 284.202(b)(2) delays the authorization of transportation of natural gas purchased from local distribution companies for a 15-day period to give appropriate state regulatory agencies with jurisdiction over the local distribution company an opportunity to oppose the transaction. If the state regulatory agency files an objection within the 15-day period, the eligible user must apply either for a transportation certificate under section 7(c) of the Natural Gas Act or for an adjustment under NGPA section 502(c) and § 1.41 of this chapter to permit the transaction to proceed.

§ *284.203 Intrastate pipeline transportation authorization.*

Implementation of fuel oil displacement transactions may require incidental transportation by intrastate pipelines. For example, sales by producers or local distribution companies attached to an intrastate pipeline would require that pipeline to transport the natural gas to an interstate pipeline for subsequent transportation to an eligible user located on the interstate system. The Commission views this transportation to be "on behalf of" the interstate pipeline if an intrastate pipeline is either receiving the natural gas from or delivering it to an interstate pipeline. As a result, the Commission will permit incidental transportation by an intrastate pipeline under NGPA section 311(a)(2) if necessary to complete a transaction permitted under § 284.202. The jurisdictional guarantees of NGPA section 601(a)(2) apply to intrastate pipelines who supply such transportation services.

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[11] See Order No. 2, 43 FR 8362 (February 8, 1978).

§ *284.204 Construction of facilities.*

Although most fuel oil displacement transactions may be implemented without the construction or operation of additional facilities, any incidental facilities needed for the sole purpose of facilitating the transportation of natural gas supplies of the eligible user may be constructed without Natural Gas Act certification if the cost is borne by the eligible user. Should new facilities be constructed for the benefit of several eligible users, the costs may be pro rated among those eligible users.

§ *284.205 General conditions.*

Section 284.205(a) requires the eligible user to obtain any necessary waivers of PIFUA (see Part III above).

Section 284.205(b) incorporates by reference the provisions governing rates, charges, terms and conditions that would otherwise apply to self-implementing transactions under section 311(a)(1) of the NGPA. For those transactions authorized under a certificate of public convenience and necessity issued under section 7(c) of the Natural Gas Act, these conditions are incorporated by reference into any such certificate unless otherwise specified in any such certificate. Transportation services authorized by § 284.203 are subject to the rates, charges, terms and conditions of Subpart B of Part 284.

The rate methodology incorporated by reference from Subpart A of Part 284 is of special importance. Section 284.103 provides that all revenues in excess of those derived from transportation included within billing determinants will be required to be credited to Account No. 191, except for either an allowance of one cent per Mcf or actual out-of-pocket cost. Several comments noted that such a flowthrough of revenues to the interstate pipelines' other customers does not provide an incentive for interstate pipelines to participate in these transactions. The Commission reemphasizes that it does not seek in this rule to create any greater incentive for direct sales than the incentive for fuel oil displacement through increases in general system supply. This reflects the Department of Energy's statement that sales from interstate system supplies is the preferred method of fuel oil displacement. Because some interstate pipelines may not have supplies available to serve their own customers' fuel oil displacement requirements, the Commission hopes that the pipeline will cooperate in addressing an important national problem by transporting volumes under the final rule.

Section 284.205(c) prescribes the duration of a fuel oil displacement transaction. Several comments suggest a two or three year term, while the Commission staff has suggested a six month term. Because of the substantial effort required in negotiating and implementing a fuel oil displacement transaction, § 284.205(c)(1) is based upon the ERA proposal for a one-year maximum term. However, the Commission recognizes that the fuel oil supply situation is changing rapidly, and believes that all transactions under the Final Rule should expire on June 1, 1980. Also, paragraph (d)(2) provides for termination prior to the end of the term of any authorization.

Section 284.205(c)(2) differs from the one-year renewal period proposed by ERA, by prohibiting extensions beyond the termination of the fuel shortage emergency period. The rule incorporates the extension procedures for section 311(a)(1) authorizations by reference. Such extensions are limited to the fuel shortage emergency period. If a transaction is authorized pursuant to a certificate of public convenience and necessity under section 7(c) of the Natural Gas Act, the Commission will treat an extension report conforming to § 284.106(c)(2) as an application for an amendment to extend the certificate.

Paragraph (d)(1) provides that the authorization under either NGPA section 311(a)(1) or the certificate will automatically terminate if the gas is diverted from an eligible use.

Termination under paragraph (d)(2) may be made by rule or order. Such actions may be undertaken on an individual, regional or national basis as the nation's fuel oil needs and the public interest require. Paragraph (d)(2) is based upon NGPA section 311(b)(6).

The ERA proposed rule included an automatic 90 day extension for eligible users purchasing gas under a take-or-pay contract. Although the Commission has provided such extensions in its direct sales programs for high-priority users, the nature of this program, insofar as it makes direct sale gas available to low priority users, and the size each sophistication of such users makes any automatic extensions inappropriate.

Section 284.205(d)(3) provides that any transportation of natural gas sold by any local distribution company may be terminated without an opportunity for a presentation of opposing views if the Governor of a state certifies that the natural gas is needed to serve certain high priority users[12] in the local distribution company's service area. The transaction then shall terminate upon 15 days notice. The Governor's action would be authorized either under applicable state statutes or by the inherent emergency police power accorded to the Governor under state law. The Governor's power under paragraph (d)(3) is independent of the Commission's rights reserved under paragraphs (d)(1), (d)(2), or (e) of § 284.205.

Section 284.205(e) reserves to the Commission the right to terminate fuel oil displacement in the event that the President declares a natural gas supply emergency under NGPA section 301.

§ *284.206 Effect upon curtailment plans.*

Section 284.206 adopts the curtailment plan provision proposed by ERA. We note that it applies only to "an interstate pipeline's customer's requirements." Several comments suggest that the curtailment plan provision is unnecessary or inconsistent with the intent of Title IV of the NGPA. Agricultural users are concerned that the program will jeopardize the availability of natural gas under NGPA section 401. On the other hand, some fuel oil users consider participation in the program to be impossibile without protection from adverse curtailment consequences. The Commission shares the concerns of both groups and adopts the provision with the expectation that any interference with our first priority of channelling natural gas through pipeline system supply will be brought to the Commission's attention to permit prompt action, including termination under § 284.205(d).

§ *284.207 Reporting requirements.*

Section 284.207(a) states the requirements that apply to all interstate pipelines which transport natural gas under this subpart. Paragraph (a)(1) requires an initial report to be filed by the interstate pipeline within 48 hours of the start of the transaction. This report will permit the Commission and the ERA to monitor the fuel oil displacement program and will provide part of the factual basis for actions under the termination provision. Paragraph (a)(2) requires a more complete report within

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[12] *Cf.* NGPA Section 303(k).

60 days of the completion of the transaction.

Section 284.207(b) requires intrastate pipelines to supply the same acquisition cost report that are required by § 284.148(a)(1)-(7). Although the referenced section specifies when reports are due, such requirements are not incorporated into § 284.207(b).

Section 284.207(c) adopts the reporting requirements proposed by the ERA. In addition, eligible users are required to file an affidavit confirming that all volumes transported under this subpart meets the requirements of this subpart. Paragraph (c) also requires additional information when a producer sells the natural gas directly to the eligible user.

§ 284.208 Certificate procedures.

Although it is likely that the majority of fuel oil displacement transactions will meet the eligibility criteria for authorization under § 284.202, transactions involving covered transportation not authorized by § 284.202(a)(1) or (2) may instead receive Commission consideration on a case-by-case basis. Section 157.206(b) of the ERA proposed rule would have made the seller eligibility requirements subject to waiver, but failed to establish a procedure for processing waiver requests. The comments of the Department of Energy indicate that request for waivers will not be considered as part of ERA's certification proceedings under 10 CFR 595.03. However, ERA reserves the right to intervene in any waiver proceeding held before the Commission.[13] The transactions considered under § 284.208 will involve sales by interstate pipelines. Because these sellers are central to the Commission regulatory responsibilities under the Natural Gas Act, careful scrutiny of such transactions is warranted.

Paragraph (a) limits this procedure to interstate pipelines which transport natural gas to eligible users. Further, intrastate pipelines proposing to sell natural gas at a price above that permitted by § 284.202(b)(1) are precluded from using this procedure. This restriction is necessary to prevent disrupting the flow of intrastate supplies to interstate consumers under NGPA section 311(b).

Paragraph (b) incorporates the filing requirements proposed by the ERA. Paragraph (b) also requires that the source of the natural gas supplies and any relevant take-or-pay obligations must be included in the application.

Paragraph (c) describes the limited 60 day temporary certificates available under this subpart. Temporary certificates will be issued during the winter heating season by action of the Commission only upon a showing of special hardship. A conforming amendment to § 3.5(f)(1)(iv) of this chapter is included to delegate the authority to issue temporary certificates to the Director of the Office of Pipeline and Producer Regulation. The Commission accepts the ERA suggestion that a fuel oil emergency exists, and is of sufficient urgency to warrant the issuance of temporary certificates under section 7(c)(1)(B) of the Natural Gas Act. In response to several comments objecting the use of temporary certificates for fuel oil displacement, the Commission will limit their duration to 60 days.

Paragraph (d) provides for an evidentiary hearing to be scheduled on an expedited basis during the 60 day period by a presiding administrative law judge to be appointed by the Chief Administrative Law Judge.

The hearing will provide an opportunity for other natural gas companies to express interest in purchasing the natural gas for pipeline system supplies. Both the sales price and the disposition of revenues will be examined.

VI. Environmental Impact

The extent that natural gas is substituted for fuel oil and the specific location of eligible users is not known and cannot be ascertained quantitatively at present since the Commission is not empowered to require substitution, but merely to act upon requests to make these transactions, the response to which will not occur until the Final Rule becomes effective. However, on the basis of preliminary inquiries to potential eligible users by the ERA it appears that eligible users would be scattered in a broad band running through the southeastern southern, and mid-western states, with some isolated users in the northeast.

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[13] Further Comments of the Department of Energy at 10.

The Commission has assessed potential impacts on air and water quality, safety land use and climate and conclude that no adverse environmental effects can be forecast due to implementation of the Final Rule. The duration of those sales will be short-term and involve no major construction of new facilities. We are pleased that all of our analyses indicate that should there be any measurable environmental effects, these would be beneficial, in the nature of localized improvements in air quality, decreased water pollution, and diminished safety risks isolated to oil tanker operations.

For these reasons we have determined that approval of the Final Rule would not constitute a major Federal action significantly affecting the quality of the human environment, within the meaning of the National Environmental Policy Act of 1969, as amended, and therefore will not require the preparation of an environmental impact statement. In a separate analysis, the ERA has made the same finding.

(Natural Gas Act, (15 U.S.C. 717 *et seq.)*, Natural Gas Policy Act of 1938, Pub. L. 95-621, Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267).)

In consideration of the foregoing, Parts 3 and 284 of Subchapter I, Chapter I, Title 18, Code of Federal Regulations, are amended as set forth below, effective immediately.

By the Commission. Commissioner Smith, dissenting, filed a separate statement appended hereto.

Kenneth F. Plumb,
Secretary.

SMITH, Commissioner, dissenting, does not believe the data submitted in support of the Order establishes a surplus of adequate size and duration sufficient to support a major change in natural gas use priority and consequently dissents to the issuance of the Order.

Don S. Smith,
Commissioner.

¶ 30,055

44 F. R. 30331 (May 25, 1979)

18 CFR Part 157

[Docket No. RM79-43]

Applications for Certificates of Public Convenience and Necessity

AGENCY: Federal Energy Regulatory Commission.

ACTION: Interim rule.

SUMMARY: Sections 311 and 312 of the Natural Gas Policy Act of 1978 allow interstate pipelines to acquire natural gas from intrastate pipelines without the prior approval of the Federal Energy Regulatory Commission. These transactions often require an interstate pipeline to construct facilities. The amendments contained in this document will allow such facilities to be constructed under a budget-type certificate authorizing the construction of "gas-purchase facilities".

DATES: Effective date: May 18, 1979. Comments due: June 18, 1979.

ADDRESSES: All findings should reference Docket No. RM79-43 and should be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Philip Yates, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 275-4214.

On November 8, 1978, the Natural Gas Policy Act of 1978 (NGPA) was enacted. Section 311(b) of the NGPA allows the Commission to authorize an intrastate pipeline to sell natural gas from its system supply to an interstate pipeline or local distribution company served by an interstate pipeline. Section 312 allows the Commission to authorize the assignment to an interstate pipeline of an intrastate pipeline's right to receive natural gas under a particular contract. Subparts C and D of Part 284 of the Commission's regulations implement these provisions of the NGPA.

To enable section 311 or 312 transactions to occur, new facilities are often needed to connect the intrastate source of supply to the interstate system. These facilities are usually minor in nature. Regulatory consistency and logic dictate that an interstate pipeline should be allowed to construct such facilities pursuant to the budget-type authority granted in § 157.7(b) of our regulations. However, that regulation was drafted before the enactment of the NGPA, and it does not presently permit such authority to be relied upon for the construction of facilities to attach system supply from intrastate sources. By this order the Commission amends § 157.7(b)(4) to include within the definition of "gas-purchase facilities" those facilities necessary to transport volumes of gas sold or assigned by an intrastate pipeline under section 311 or 312.

In this regard, the Commission deems all existing budget-type certificates issued pursuant to section 157.7(b) to be sufficient authorization for construction pursuant to the expanded definition of "gas-purchase facilities" promulgated by this interim rule.

The availability of budget-type authority for the facilities in question should begin at once in order to implement as rapidly as possible those section 311 or 312 transactions which are currently delayed since, absent this authority, the purchasing interstate pipeline must await issuance of a Natural Gas Act section 7 certificate.

Accordingly, the Commission finds that good cause exists to dispense with the normal notice and public procedures prior to making this rulemaking effective, since they are impracticable, unnecessary and contrary to the public interest. This interim rule shall become effective immediately.

Interested persons are invited to submit written comments, data, views, or arguments with respect to this proposed language. All comments received within 30 days of the date of this order will be considered prior to the promulgation of final regulations. The Commission is currently considering other revisions to § 157.7. These amendments are contained in the notice of proposed rulemaking entitled "Proposed Rulemaking Respecting Budget-Type Applications for Gas-Purchase Facilities." [1] The comment period for the Docket No. RM79-37 proposed rule concludes on May 25, 1979. Any comments received pursuant to this Notice will also be considered in Docket No. RM79-37.

An original and 14 copies of comments should be filed with the Secretary of the Commission. All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, 825 North Capitol Street, N.E., Washington, D.C., during regular business hours. Comments should be submitted to the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should reference Docket No. RM79-43.

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[1] Docket No. RM79-37, 44 FR 24103 (April 24, 1979).

¶ 30,056

44 F. R. 31170 (May 31, 1979)

18 CFR Part 273

[Docket No. RM79-3]

Natural Gas Policy Act of 1978; Collection Authority; Refunds; Final Rule

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final Rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) has promulgated the rule herein to complete the Commission's process of establishing rules to carry out its statutory responsibilities pursuant to section 503(e) of the Natural Gas Policy Act of 1978 (NGPA). This rule amends §§ 273.202(c), 273.204(a)(2) and 273.204(b) by extending the filing dates in each of the above sections from March 1, 1979, to April 1, 1979.

EFFECTIVE DATE: March 1, 1979.

FOR FURTHER INFORMATION CONTACT: Kenneth F. Plumb, Secretary, Federal Energy Regulatory Commission, 825 North Capitol St., N.E., Washington, D.C. 20426 (202) 275–4166.

SUPPLEMENTARY INFORMATION: On December 1, 1978, the Federal Energy Regulatory Commission (Commission) issued Interim Regulations implementing the Natural Gas Policy Act of 1978 (NGPA). Although the Interim Regulations were effective upon date of issuance, the Commission called for a sixty day comment period which ended January 31, 1979. After consideration of the comments filed, this order amends the Interim Regulations, Part 273, without an additional comment period.

Part 273 of the Interim Regulations sets forth procedures for the interim collection of prices, subject to refund, for certain categories of natural gas for which a determination of eligibility is made by a jurisdictional agency. Specifically, § 273.202 deals with the collection of such prices pending a jurisdictional agency determination of eligibility. Section 273.202(c) places a special limitation on the period of collection. It suspends such collections after March 1, 1979 unless the Commission is notified in writing that "the jurisdictional agency has authority to process applications for determinations under Subparts B, C, G, and H of Part 271 and is making such determinations."

Section 273.204(a) sets forth the general rule for retroactive collection after the final determination and allows retroactive collection for first sales of natural gas delivered after November 30, 1978, if the application for determination was filed by March 1, 1979. Section 273.204(b) places a special limitation on the period of collection. It suspends retroactive collections authorized in § 273.204(a) for deliveries commencing March 1, 1979, unless the Commission is notified in writing by March 1, 1979, that "the jurisdictional agency has authorized to process applications for determinations under Subparts B, C, G, and H of Part 271 and is making such determinations."

Prior to the March 1, 1979 filing date, many jurisdictional agencies have notified the Commission that they have the authority to make and are making these determinations. However, due to varied internal state situations, a limited number of jurisdictional agencies have not yet filed this statement of authority.

To date, the Commission has received numerous comments from producers, producer associations, and jurisdictional agencies requesting an extension of the March 1, 1979 deadlines in §§ 273.202(c) and 273.204 (a) and (b). After consideration of the comments filed, it is the Commission's understanding that these varied state situations can be resolved in the near future. The Commission is further informed that the jurisdictional agencies are presently endeavoring to obtain the legal authority necessary to make the NGPA Section 503 determinations. (*See, e.g.*, the filing of the Governor of the State of Oklahoma).

Accordingly, the Commission finds that good cause exists to amend §§ 273.202(c) and 273.204(b) of the Interim Regulations by extending the time for filing the statement of authority from March 1, 1979 to April 1, 1979, and to amend § 273.204(a) of the Interim Regulations by extending the time for filing an application for determination from March 1, 1979 to April 1, 1979. In light of the need for prompt Commission action in these circumstances to forestall the imposition of unnecessary burdens, and in view of prior Commission action in holding public hearings and soliciting comments on these regulations (43 FR 53270 (November 15, 1978), and 43 FR 56448 (December 1, 1978)), the Commission also finds that good cause exists to issue these amendments without further notice and comment; and that the amendments should be made effective immediately.

¶ 30,057

44 F. R. 33847 (June 13, 1979)

18 CFR Part 290

[Docket No. RM79–6]

Procedures Governing Collection and Reporting of Information Concerning Cost of Providing Retail Electric Service

June 5, 1979

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final regulations.

SUMMARY: These regulations implement section 133 of the Public Utility Regulatory Policies Act of 1978 and establish procedures governing the collection and reporting of information concerning the cost of providing retail electric service.

DATES: Effective July 15, 1979. Written comments on § 290.404 (d) and (f) by July 15, 1979.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 (Reference Docket No. RM79–6).

FOR FURTHER INFORMATION CONTACT:

Gregory Martin, Office of Commissioner Matthew Holden, 825 North Capitol Street, NE., Room 9010, Washington, D.C. 20426 (202) 275–4176.

William Lindsay, Office of Electric Power Regulation, 825 North Capitol Street, NE., Room 5200, Washington, D.C. 20426 (202) 275–4777.

Jane Phillips, Office of the General Counsel, 825 North Capitol Street, NE., Room 8000, Washington, D.C. 20426 (202) 275–0422.

SUPPLEMENTARY INFORMATION: In this final rule, we seek to implement section 133 of the Public Utility Regulatory Policies Act of 1978 (PURPA) Pub. L. 95-617. This provision of the statute requires the Federal Energy Regulatory Commission (Commission) to prescribe, within 6 months of enactment, the methods, procedure and format to be used by electric utilities in gathering information necessary to determine the costs of providing electric service.

We have made an intense effort to inform electric utilities, their customers, potential intervenors and State regulatory agencies about both the nature of thinking and the timing of action within the Commission. Since last November we have held a variety of staff-level conferences with interested persons, the details of which are recorded in the public file. On December 4, 1978, an informal conference was held to elicit the views of interested persons, and on January 13, 1979, representatives of the Commission met with Commissioners from sixteen State regulatory authorities constituting the Ad Hoc Committee on the National Energy Act of the National Association of Regulatory Utility Commissioners (NARUC).

Various memoranda, correspondence and drafts concerning concepts of the Commission's responsibilities regarding section 133 have been placed in the public file and have been reported in the trade press. The product of this procedure was the Notice of Proposed Rulemaking in Docket No. RM79-6, adopted by the Commission on March 1, 1979, and printed in the Federal Register on March 7, 1979 (44 FR 12438).

In order to avail ourselves of the opportunity for comment on the rule, we held four regional hearings on the proposed rules in addition to soliciting written comments. During the 30-day comment period the Commission received, in addition to the 626 pages of regional hearing transcript, more than 230 oral and written comments from over 160 utilities, State regulatory authorities and consumer groups. Because of the range, number and complexity of these comments the Commission was unable to issue a final rule within the prescribed time limits and issued on May 8, 1979 (44 FR 29102) a Notice of Intent to Act in promulgating final regulations by May 30, 1979.

The Commission has considered carefully all of the testimony and all of the written comments received on its Notice of Proposed Rulemaking, including the 60 or more comments that were filed as many as two weeks after the close of the comment period.

The procedure which we have followed is, we posit, in more than substantial compliance with the requirements and spirit of the Administrative Procedure Act and any other applicable provisions of law, as well as the requirements of elementary fairness and good sense.[1]

Basic Determination

Upon careful review, we have concluded that the basic concept of the proposed rule was correct, although we have been persuaded to limit many of the specific data requirements originally contained therein.

The Joint Explanatory Statement of the Committee of Conference succinctly summarizes at page 86 the general purpose of section 133:

> The conferees intend that good information with regard to costs of providing service must be readily available on a timely basis to everyone concerned.

In preparing its rules under section 133, the Commission was faced with certain key questions as to what would constitute good information readily available on a timely basis. Those issues include: The nature of the cost data to be reported (i.e., whether accounting, marginal or both costs should be required); the extent of reporting (i.e., whether raw data or calculations should be required); and the format for reporting (i.e., whether information should be supplied in Form 1 or in a discrete form for section 133 alone. The initial discussion in this Preamble focuses on these three issues. The Commission has also undertaken a section by section analysis of the comments, keyed to the provisions in the proposed rule and has indicated what position it has adopted in the final rules.

Accounting or Marginal Costs—Legal Issues

Several commentators, mostly utilities, maintained that to require marginal cost data would go beyond the minimum requirements of section 133 since that section of PURPA does not contain any explicit reference to marginal costs or marginal cost pricing. One of these commentators [2] further asserted that "the Commission lacks the statutory authority to compel the submission of marginal costs." This same commentator [3] also argued that it was "reasonable" to assume that when it used the term "costs" in Title I, Congress intended reference to the industry's understanding of the term as referring to embedded costs or fully allocated costs.

In the proposed rules, we interpreted the obligation to insure that "good information with regard to [the] costs of providing service * * * be readily available on a timely basis to everyone concerned * * *" to require the gathering and reporting of both marginal and accounting cost information. Paragraph (a) of section 133 lists four broad categories of information that are to be required under this rule, and then states: "Such rules shall provide that information required to be gathered under this section shall be presented in such categories and in such detail as may be necessary to carry out the purposes of this section." The Commission interprets this as providing considerable latitude for the exercise of its judgment, including the authority to require both accounting cost information and marginal cost information.

It is true that Title I of PURPA does not use the words "marginal costs." However, Title I does not specifically mention accounting or embedded costs either. We do not dispute that this Commission and various State regulatory commission have typically used the term "costs" as synonymous with embedded or fully allocated costs. However, the legislative history of Title I of PURPA suggests that Congress wanted State regulatory authorities and non-regulated utilities to conduct a thorough reevaluation of retail rate structures. State regulatory authorities and non-regulated utilities cannot begin to make decisions on the issue of whether marginal or embedded costs are more relevant for utility cost of service calculations unless they are provided information showing what the numbers look like under the two approaches. The Commission will not interpret section 133 so as to bar the reporting of marginal cost information and thus hinder such an inquiry.

Accounting or Marginal Costs—Policy Considerations

We also received a variety of policy and procedural arguments against the marginal cost reporting requirement. Several commentators urged us not to set forth data requirements but instead to accept as sufficient for complying with section 133 whatever information is currently supplied to State regulatory authorities. Others argued that it would be duplicative to require both accounting and marginal cost data, and that the utility or its State regulatory authority should be allowed to choose the appropriate type of data necessary for performing cost calculations.

It is our belief that Congress included section 133 in PURPA to ensure the availability of adequate cost and load data in all states. The regulations would not comply with the intent of Congress if they simply required the submission of whatever cost of service information is currently supplied to the relevant State regulatory authorities.

Many of those who objected to requiring marginal cost data imputed to the industry a lack of familiarity with marginal cost concepts and contended that marginal cost calculations were imprecise and subject to considerable speculation. These commentators argued that accounting cost data are more familiar to the industry and would therefore be more reliable.

The contention that industry is not familiar with marginal cost methods appears overstated. We estimated that marginal cost studies have been initiated or completed for approximately fifty of the one hundred and ninety utilities that will be required to comply with the section 133 reporting requirements in November 1980. Nor do we agree that accounting cost calculations will necessarily be more reliable. We do not dispute that accounting or embedded costs have been the industry norm for many years. However, such costs have not been used extensively for determining time differentiated costs. Section 133, in contrast, emphasizes the need to determine how costs differ by time of day and season of year. No present methods for determining time differentiated accounting costs are very advanced. As one respondent commented, "The time differentiation of accounting costs, as you know, is probably subject to [as] much uncertainty and debate at this point, as are most of the aspects of the marginal cost studies." [illegible]

Calculations or Raw Data

In preparing its rules under section 133, the Commission recognized that it had the discretion to require only raw information which could then be used as the basis for calculating costs by costing periods, by customer group and by voltage level or to require calculated costs for such functions and customer groups. The question was raised of whether the reporting requirements should have been limited to raw data or should also have included calculated costs. In its Notice of Proposed Rulemaking the Commission recognized that the information must be calculated in order to be useful and posed the question of where the burden of such calculations should lie: with the utility providing the information or with each of the potential users of the information.

Over a third of the participants in this rulemaking addressed this question. Several indicated that the decision should be left to either the discretion of the utility or to the relevant State regulatory commission. Those arguing against supplying more than raw information asserted that the benefits accruing from such calculations would not outweigh the associated expenses and emphasized that such expenses would ultimately be borne by ratepayers. Those supporting the requirement that utilities submit calculations generally argued that it would be easier and less expensive for the submitting utility rather than outside parties to make the calculations.

Under the final rules, the Commission has required the submission of both raw information and calculations. The Commission believes that there are several advantages to requiring both raw information and calculations. First, the availability of calculated costs will lead to more informed participation by various intervenors in retail rate proceedings. We agree with one comment that many State regulatory commissions "do not currently have the expertise necessary for conducting in-house cost of service studies * * *." [4] The resources of environmental and residential consumer groups are generally even more limited. One commentator indicated in this regard: "We cannot overemphasize the importance of requiring the utilities to complete the summary table * * *. Limiting the utilities' responsibilities to the compilation of raw data would restrict the ratesetting process to those groups able to hire expensive consultants before intervening in a rate case [and] * * * would tend to exclude consumer and environmental groups from the ratemaking process* * *." [5]

If intervenors and State commission staffs do not have ready access to cost of service information, in a manageable form, the quality of the deliberation will suffer or the proceedings will be delayed until the data become available to all parties. We would be remiss if we promulgated regulations which produced either result.

A second advantage of having utilities perform calculations is the likelihood that confusion about what the data actually means, in the understanding of the utility, will be minimized. One utility commented that "misinformation and misunderstanding will be reduced with the utilities performing the marginal cost studies".[6]

A third advantage to such calculations is that they avoid unnecessary duplication of effort. Not every calculation is subject to dispute in a typical rate case. There are often broad areas of agreement between the different parties in a rate proceeding. If the reporting utilities perform certain calculations, State commissions and intervenors can focus their more limited resources on controversial and disputed areas.

The fourth advantage is that other users of the information will have a better opportunity to understand the unique circumstances of the particular utility. The calculation of time differentiated rates, based on either accounting or marginal costs, is a relatively new area for both the industry and State regulatory commissions. We have tried to draft regulations that would accommodate calculation of time differentiated costs based on any one of the several principal approaches. Each utility's particular circumstances will suggest the selection of one approach as preferable to another. After they have performed such calculations "utilities will be in an excellent position to suggest improvements." [7]

One commentator strongly objected to requiring calculations and argued that:

> * * * an information gathering procedure which allows the utility to select marginal and embedded cost methodologies rather than providing raw information is necessarily inconsistent with the purposes of PURPA. First, it allows the utility to define and structure the raw materials for ratemaking proceedings to its own purposes. Intervenors will only be able to derive the raw information necessary to construct contrary positions by "unbundling" the utility cost study to get at its premises and raw data.[8]

A different commentator, representing low income residential customers, also objected to the calculation requirement, contending that it would only serve to cut off "a full review of the issues involved".[9] We disagree that the calculation requirement as provided would serve to cut off debate on controversial issues.

We do not intend that raw information be hidden within the cost calculations although it appears that the regulations as proposed might arguably have permitted such a possibility. (See §§ 290.501(d) and 290.502(d).) The final rules are specifically designed to emphasize that all of the accounting cost, marginal cost and load information (specified in Subparts B, C and D) must be provided separately from and in addition to whatever cost calculations are developed in compliance with Subpart E. Therefore, an intervenor wishing to dispute the Subpart E calculations will not have to "unbundle" any calculations to gain access to raw information. Utilities will have the discretion to choose whichever method they deem appropriate for their system. However, if an intervenor disagrees with the method selected, the information necessary to develop alternative calculations will also be available.

In summary, requiring the calculations will provide a common point from which all parties can commence an analysis of rate design issues. Requiring that the supporting raw information also be provided will assist those who wish to challenge the assumptions underlying the chosen cost methodology or to propose a different methodology.

The Commission recognizes that requiring both raw and calculated information imposes certain costs on the reporting utility, at least if it has not previously conducted marginal cost studies. At each of the public conferences we asked for estimates on the cost of supplying marginal cost data and on the cost of preparing a marginal cost study. The purpose was to provide the Commission with an informed basis to adjudge the reasonableness of any such requirement. The estimates of initial cost, as provided by utility managements, ranged from $40,000 to $656,000. Most estimates fell in the $50,000 to $150,000 range.[10] The average electric operating revenues in 1977 for the 258 utilities covered by section 133 of PURPA were approximately $248 million. This implies that the additional cost incurred to comply with Subparts B, C and E will typically range from 0.02 to 0.06 percent of electric operating revenues. The Commission believes that these costs are not unreasonable in light of the potential benefits to be gained in providing all sides—utilities, large industrial customers, residential users, *et al.*—with full opportunities to participate, on the basis of good information, in the consideration of electric rate issues.

In addition to the question of cost calculations proposed under Subpart E, we solicited comments as to whether we should require that utilities calculate marginal energy costs and annual carrying charge rates. With regard to the question of whether utilities should be required to report calculated marginal energy costs, as specified in § 290.303, or whether it is reasonably possible for users of the reported raw information to calculate those costs from the raw information, the comments followed essentially the same pattern as those regarding the calculations specified in Subpart E. With regard to whether or not utilities should be required to submit calculated annual carrying charge rates as specified in § 290.307, a majority of those responding indicated that they preferred that calculations be required. Most did not strenuously object to providing raw information to support those calculations.

For those reasons discussed regarding calculations in Subpart E, the Commission will require the calculation of marginal energy costs and annual carrying charge rates in the final rules.

Format for Collection of Raw Information

In the Notice of Proposed Rulemaking, the Commission solicited comments as to whether an entirely new form or a modified FERC Form 1, already required to be filed by a number of the utilities required to report under section 133, should be used for the submission of information.

Based upon comments[11] and its own evaluation, the Commission has chosen not to modify Form 1 but rather to create a new form. To the extent that information already required by FERC Form 1 is included in the filings required by section 133, the simple transfer of that information from Form 1 to the new form should be easily accomplished.

The Commission was concerned that modification of Form 1, which presently serves a useful accounting function, would create confusion for both utilities and potential users of the information submitted under section 133. In addition, many utilities indicated that modification of Form 1 would require substantial modification of programs designed to comply with its present requirements.

Subpart A—Coverage, Compliance and Definitions

§ 290.101 Coverage.

The language of both the proposed and the final rule tracks the statutory language of section 102 of PURPA in designating what utilities will be required to report under Part 290. A utility would be required to report beginning in the first even-numbered calendar year not less than two years following the first year (after December 31, 1975) in which it had the requisite volume of retail sales but no earlier than 1980. Such utility will also be required to report biennially for all future years even if its volume of sales in those years falls below the statutory threshold. Although the Secretary of the Department of Energy is required under section 102(c) of PURPA to publish a list of the covered utilities, omission from this list will not relieve a utility covered under § 290.101 from the reporting requirements of Part 290.

A number of smaller utilities stated that 500 million kilowatt-hours annual retail sales is too low a threshold for coverage. They argued that the cost of compliance is unfairly burdensome to smaller utilities, and is proportionately higher for them than for large utilities.[12] In addition, some municipal utilities and rural electric cooperatives argued that the administrative ratemaking procedure applicable to them is such that the information required under the proposed rules would serve neither the purposes of section 133 nor any other useful purpose.[13]

The coverage of section 133, as a part of Title I of PURPA, is stated in section 102 of the Act. The Commission does not have authority to change that coverage. We observe further that the purpose of section 133[14] is equally applicable to large and small utilities. We are concerned, however, about the effect of immediately imposing this new reporting requirement on small utilities. Therefore, we have included a special two year extension for utilities having annual retail sales of less than one billion kilowatt-hours. Such utilities will be relieved from reporting now or at any future date that information which they would otherwise be required to report in 1980. We expect that in this two year period before the first filing is required, these small utilities will be able to make the managerial and technical preparations required to meet the requirements of this part as economically as possible. We also expect that the two year period will provide an opportunity for some small utilities to establish joint load research programs so as to reduce the costs of compliance for each participant. This extension is granted for such good cause and is contained in § 290.102(d).

Several utilities[15] argued that no useful purpose will be served by applying the requirements in Part 290 to them. The Commission has granted such generic extensions and exemptions in this part as it deems necessary and would expect such utilities to seek any additional relief through the exemption and extension procedures provided in Subpart F.

The Tennessee Valley Authority suggested "a special reportihg procedure whereby an electric power supplier, such as TVA, which is both a covered electric utility within the meaning of PURPA and the sole source of power at wholesale for an integrated system of other electric utilities subject to the reporting requirements of section 133, may file a consolidated report for itself and for its covered distributing utilities. Such a provision would be especially appropriate in cases in which the wholesale supplier designs the resale rates applied by the distributing utilities."[16] The Commission accepts this suggestion and has embodied it in § 290.102(c) of the final rule.

§ *290.102 Compliance.*

The proposed rule established when and for what periods of time information specified in Subparts B, C, D and E were to be reported and the manner in which information was to be provided to the public.

§ *290.102(a) Information gathering and filing.*

Comments were received from a number of utilities objecting to the burden of providing copies of filings for public inspection at their own offices, and suggesting that State regulatory agencies or this Commission perform this function. Other utilities requested that the rule state that they would not be required to bear the cost of providing copies to requesting parties.[17]

We believe that public access to the information in filings under this rule is as important as the quality of the information reported. Although providing for public inspection and copying may require additional public information resources for some utilities, we believe this is well justified by the importance of the information. Therefore, we continue to require that copies be available at each utility's principal offices. We agree with the comments regarding cost of reproduction, and have made such modification in the final rule.

§ *290.102(b) Time of filing and reporting period.*

There were many comments on this paragraph of the proposed rule. Most recommended changes to either the filing dates or the six-month staleness limitation so as to encourage or at least permit use of the most recent calendar year as the reporting period.[18] We have adopted this approach in § 290.103(b) of the final rule and have further provided in § 290.103(c) for the case in which a utility has recently gathered information in connection with a retail rate proceeding. If information so gathered is based on a reporting period reasonably near the "most recent calendar year," it serves no interest to require the utility to do additional data gathering and calculations to comply with our requirements. We will, therefore, permit the alternative submission of the equivalent information.

We have changed the biennial filing date from November 1 to May 31 for filings after that required in 1980 so as to improve the currency of the calendar year data in each filing.

§ *290.102(c) Filing of information at the time of application for a rate change.*

The proposed rule included a requirement for gathering and filing information specified in Subparts B, C, D and E at the time of making an application or proposal for a rate increase. A number of commentators[19] objected to this requirement on the grounds that it is either not required or prohibited by section 133 of PURPA. The Commission agrees that section 133 does not specifically require gathering and filing of cost information more frequently than every two years. However, the Commission clearly was given the authority in the first sentence of section 133(c) to require such additional filings if it deemed them appropriate. Considering the purposes of section 133, it may be reasonable to expect that the greatest need for the cost information by regulators and others will occur at the time of a proposal for a rate change. If a concurrent gathering and filing is not required, the question arises as to the usefulness, in the rate proceeding, of the most recent cost information filed pursuant to these rules. With regard to this, it seems clear that the needs most likely to be met by information filed under these rules will relate to consideration of rate structure rather than rate level. The currency of data is certainly an essential factor in addressing questions of rate level, but tends to be less important in considering rate structure, because the relationships among costs tend to persist over longer periods of time even though the overall level of costs may change significantly. A regular biennial filing requirement will permit utilities to schedule resources for this task on a regular basis, integrated with related reporting requirements, so as to avoid costly variations in data-related workload.

There is no doubt that the rate increase filing requirement as stated in the proposed rule would have added a significant reporting burden to the requirement that utilities make information filings every two years. On balance, the Commission concludes that it will not require a separate gathering and filing of the data specified in Subparts B, C, D and E at the time of a proposed rate increase. The purposes of section 133 will be served adequately by the biennial filing prescribed in the final rule. The Commission believes that the public access provisions of § 290.102 are sufficient so that no additional publication is necessary at the time of any rate increase application.

The issue of what information is needed at the time of application for a rate increase is one that the Commission will continue to review as a part of the ongoing effort to improve these rules.

§ *290.103 Form of the information.*

The question of whether to use Form 1 or other existing forms as vehicles for submissions under this rule has previously been discussed. It is the Commission's intention to provide suitable standard forms for certain items of data required under this rule and to prescribe the general acceptable forms of presentation for the remainder. The rule as proposed has been retained and appears in § 290.102(b).

Additional Provisions

The Commission has added several additional provisions to this subpart:

§ *290.102(c) Consolidated reporting by certain wholesale suppliers.*

§ *290.102(d) Extension for small utilities.*

§ *290.104 Cost of compliance.*

§ *290.105 Definitions.*

Sections 290.102(c) and 290.102(d) have been discussed above. The question of proper accounting for the costs utilities incur in the gathering and filing of information under these rules was not addressed in the proposed rule. The Commission has considered this question and has determined that, since the information collected involves only retail service, the corresponding costs should be treated as an expense of regulation to be recovered through retail revenue. Accordingly, as indicated in § 290.104 of the final rule, these expenses will not be allowed by the Commission in establishing wholesale rates.

In comments on the proposed rule, a number of parties requested more complete definition of certain terms. Others comments pointed out the possible misapplication of the rule as proposed, particularly with respect to jurisdictional questions. Section 290.105 has been added to the rule and provides definitions for the following:

State Regulatory Authority. The definition of this term is taken directly from paragraphs 15, 16 and 17 in section 3 of PURPA.

Retail Regulotory Jurisdiction. This definition is included in response to comments [30] indicating that separate reporting for each State regulatory authority as defined above would have been overly burdensome because original jurisdiction is assigned to municipalities in the State of Texas by the laws of that State. The definition identifies those subdivisions of regulatory authority for which separate reporting will be required for certain items of information, particularly load data.

It was not intended in the proposed rule that separate reporting of load or other data would be required relative to operations in political subdivisions smaller than states. The definition implements this limitation on separate reporting.

Predominant Retail Regulatory Jurisdiction. Several comments [21] suggested that a more complete definition was needed for this term, which is used in several sections of this part. For example, it is used in § 290.307(a)(1) to specify what method is to be used for the calculation of annual carrying charge rates.

Voltage Level. Both the proposed rule and the final rule require reporting of certain data by voltage level. A separate definition of this term has now been provided.[22]

Typical Day Costs and Loads. This definition was originally included in Subpart D on Load Data, and is discussed below.

Subpart B—Accounting Cost Information

General

As proposed the rule required the submission of the following information in order to develop fully allocated cost of service studies: rate base information including plant, depreciation, prepayments, accumulated deferred income tax, materials and supplies, electric plant held for future use, nuclear fuel material and construction work in progress data; operating expense information including operation and maintenance expense and tax data; and rate of return information. This accounting cost information coupled with the load information is intended to permit the development of fully allocated accounting cost of service studies under a variety of methods currently in use.

About one third of the parties submitting comments on the proposed rule made specific comments on Subpart B. In general, the comments were of a technical nature. The only policy matter raised was the concern of a number of publicly owned utilities that the account structure (the FERC Uniform System of Accounts) on which Subpart B is based is not completely applicable to them, and that they should be permitted to report information based on their own account structure.[23] The data in Subpart B have been referenced to the FERC Accounts in order to achieve as much uniformity as possible in reporting. It is recognized that publicly owned systems do not keep their books in accordance with the FERC Uniform System of Accounts. The rule requires the public systems to follow FERC accounts only to the extent practicable.

§ 290.201 Rate base information.

Section 290.201 of the proposed rule required balances to be reported at the beginning and end of the reporting period together with the average of the thirteen monthly balances, if available.

Various comments [24] were received stating that the utilities do not close their books at the end of each month and that such a requirement would be costly and burdensome. Additional commentators [25] indicated that only end of reporting period data should be shown or that the data should be reported in a manner consistent with the rate base requirements of the State regulatory authority. The reporting of beginning and end of year balances appears to provide sufficient information to allow flexibility in preparing cost of service studies when coupled with a requirement that the average of the thirteen monthly balances be provided if required by the State regulatory authority. Accordingly, the regulations have been revised to require averaging of the thirteen monthly balances only if required by the State regulatory authority.

Section 290.201(a) of the proposed rule required plant data to be provided for various specified accounts and for any sub-accounts. Numerous comments were received questioning what was meant by sub-accounts. These comments indicated that a wide variety of sub-accounts are available for both plant accounts and operating and maintenance accounts. The comments [26] stated that the sub-accounts are utilized for such things as internal accounting cost controls and argued that the requirement to report such sub-accounts would be unduly burdensome without countervailing benefits unless specific sub-accounts were named for which information would be required. The requirement for sub-account data was originally proposed for added flexibility in preparing fully allocated cost of service studies. Such data may be of assistance in the functionalization, classification and allocation of costs, and the Commission originally intended to require detailed information in the event that a complete "raw data" approach was adopted. Since the final rule requires detailed calculated cost of service data in Subpart E, with appropriate supporting backup information, the amount of detailed "raw data" required in Subpart B is no longer as great. Submission of sub-account data is not now considered necessary in order to perform an independent cost of service review of the utility's analysis submitted in Subpart E, and the rule has been revised accordingly by deleting the reference to sub-accounts.

Section 290.201 (a)(2), (a)(3) and (a)(4) of the proposed rule required: A functional breakdown of distribution plant into demand and customer related components and an explanation of the functional allocation used; a breakdown of demand related transmission or distribution plant assigned different service levels and an explanation of this allocation; and a breakdown of all plant directly assigned to customer classes. Various comments [27] indicated that such information is not directly available from accounting records and that such information must necessarily be calculated or estimated. Although Subpart B of the proposed rule was entitled "Accounting Cost Information," the Commission realizes that some of the requested data will have to be derived from data in the books of the reporting utilities. In developing fully allocated cost of service studies, some calculations and manipulation of accounting cost data are necessary, and, as numerous non-utility respondents indicated, these initial calculations are best done by the reporting utilities. At least one commentator suggested that distribution costs be broken down in even greater detail. Upon reconsideration, these particular data requirements are probably most logically placed in § 290.501(b) of Subpart E. Accordingly, the rule has been so revised, leaving it to the utility to develop support for the costs assigned to various classifications, functionalizations and voltage levels.

Section 290.201(b) and (c) of the proposed rule required depreciation data by plant account. Many commentators [28] correctly pointed out that the depreciation accounts are not kept in this manner. These comments state that such reporting would require a substantial revision of current accounting practices or would require the calculation of estimated amounts. Substantial modification of current accounting practices should not be necessary for the purpose of gathering sufficient information to develop fully allocated cost of service studies. The rule has been revised to require depreciation data to be shown by primary function as currently required under the FERC Uniform System of Accounts.

Section 290.201(d) of the proposed rule required certain cash working capital information. Although this section has not been changed, it has been moved to § 290.501(b) of Subpart E because it is more logically related to the utility's method of developing its calculated accounting costs.

Section 290.210(e) of the proposed rule required various information with respect to construction work in progress for each project under construction. Several utilities stated that the data requirement was too extensive in that a great number of projects are under construction from time to time, many of which are relatively small. Various commentators[29] suggested that, if retained, the data be limited to major production and transmission projects. Others commented that the data be combined into functional groups or that dollar thresholds be established. These suggestions are incorporated in the final rule. The detailed information is required only for the major generation and transmission projects, whereas the remaining projects may be grouped by primary function and the account balances reported for each of the primary functions. Other comments suggested that CWIP be reported only if permitted to be included in rate base by the State regulatory authority. Since the data requirement as modified should be readily available, it has been retained to permit flexiblity in the development of cost of service studies. The comments indicated that § 290.201(j) inadvertently omitted certain of the nuclear fuel accounts. This has been corrected in § 290.101(i) of the final rule.

§ *290.202 Operating Expense Information.*

Section 290.202 (a)(2), (a)(3) and (a)(4) of the proposed rule required various functional and classification breakdowns of operating and maintenance expenses similar to the plant accounting data. Consistent with the treatment of those items indicated above, this data requirement has been transferred to Subpart E.

Section 290.202(a)(5) of the proposed rule required the utility to estimate the monthly fuel expense for each of the costing periods determined in § 290.308 in Subpart C. Various comments [30] indicated that such data are not readily available from accounting records. A few comments indicated that more extensive data are necessary for these estimations such as hourly average fuel expense for all hours of the year and the costs of purchased power. This data requirement is similar in some respects to that contained in § 290.303 of the final rule regarding marginal energy costs. The section has been amended in a similar manner. The utility will be required to report estimated hourly average energy costs (including both generation and purchased power) per kilowatt-hour for total retail load and for all firm wholesale load for a typical weekday, a typical weekend day and the system peak day for each month of the reporting period. Although this will not require data for all hours of the year, it will permit the reconciliation to average monthly or annual energy costs and permit the development of time-of-day rates. Since estimated data are all that are required, substantial changes in the accounting for fuel expenses will not be required.

§ *290.203 Income and revenue related tax information.*

Section 290.203 of the proposed rule required the utility to collect certain information to permit the calculation of income and sales taxes in costs of service. Various comments[31] requested clarification as to what was intended by the term "sales" tax. The reference to "sales" has been deleted from the final rule and has been replaced with the term "revenue related." This makes clear that the information required concerns those taxes which are based on the utility's revenue and not those taxes paid for "sales" in connection with utility purchases of goods or services. Some respondents requested clarification as to whether gross receipts or franchise taxes should be included. Gross receipts are clearly revenue related. Franchise taxes should only be reported if they are computed based on revenue.

§ *290.204 Rate of return information.*

Section 290.204 of the proposed rule required the reporting of rate of return information averaged for the reporting period. Some comments indicated that only end of year data should be used. Other comments stated that the data should be consistent with State regulatory authority requirements. One comment [32] stated that this section should follow exactly the format provided in 18 CFR 35.13 (filing requirements for wholesale rate increase applications). There were also comments suggesting that a requirement should be added for reporting the estimated cost of common equity and the book value of common equity. Several publicly owned utilities commented on the need for recognizing their financial structure in relation to this section. The rule has been revised to require both beginning and end of year balances. This will permit the use of end of year data or permit the calculation of average reporting year requirements, if appropriate, in the particular jurisdiction. The requirements of § 35.13 have not been used because those data relate to the Commission's wholesale jurisdiction. The publicly owned systems will be free to conform their reporting to their financial structure. Like other portions of the accounting cost section, it is recognized that the publicly owned systems will be required to conform to the specified FERC Uniform System of Accounts only to the extent practicable, recognizing their separate accounting conventions. The accounting cost section does not include the estimated cost of common equity because such information is more appropriately solicited in Subpart E as backup for the utility's calculated costs.

A new § 290.205 has been added to Subpart B, which parallels § 290.308 for marginal costs. It requires the utility to design and report costing periods which group together contiguous hours of similar accounting costs in an administratively feasible manner.

Some comments [33] requested additional information in order to permit more accurate cost of service analyses, such as allowance for funds used during construction or the operation of fuel adjustment clauses. Because these data items were substantially incorporated in the proposed rule, we do not believe that any further modification in the final rule is necessary.

Subpart C—Marginal Cost Information

One general objection raised against the collection of marginal cost information was that it "would lead to anti-competitive price differentials". One respondent [34] argued that our "proposed rule fails to consider the serious anti-competitive impact that could result from the piecemeal application of marginal cost based rates by electric utilities throughout the United States."

While we are sympathetic to concerns about "anti-competitive price differentials," we have difficulty following the line of reasoning presented. Section 133 requires the establishment of rules for the collection of cost information. We have responded by requiring both accounting and marginal cost information. Neither section 133 nor any other part of PURPA gives us authority to establish retail rates. That authority lies firmly with State regulatory commissions and non-regulated utilities. Imposition of certain data requirements in these regulations does not require that the commissions or non-regulated utilities employ a specific methodology in setting retail rates.

Even if a State commission or non-regulated utility were to adopt time differentiated rates based on the marginal cost information produced by the section 133 regulations, it does not follow that the establishment of such rates will necessarily lead to "anti-competitive price differentials." Much would depend on the particular circumstances. Among the factors to be considered would be whether there is competition for the loads of customer groups subject to the different rates and whether the partial availability of time differentiated rates based on marginal costs was not cost justified. For example, it is quite possible that time differentiated marginal cost based rates may be initially offered only to one customer group because the metering costs of general implementation would be too high. In that situation, the partial implementation of these rates would probably be cost justified. None of these issues was addressed in the comments; nor do we see how they could be addressed without reference to the specific circumstances of a particular utility.

The concern expressed is more appropriately directed toward time differentiated rates in general, and not just at time differentiated rates based on marginal costs. As the respondent noted, it is "incorrect and misleading" to associate "time-of-use rates and rates based on marginal cost as being synonymous." Time of use rates may be based on either marginal or embedded costs. It appears that once marginal cost rates are adjusted for the total revenue constraints they may look very similar to time differentiated rates based on accounting costs. One would then need to consider, among other factors, whether the potential for "anti-competitive price differentials" resulted from the sequential availability of time of use rates rather than from the cost calculations that were used to produce such rates.

Six utilities[35] expressed concern that some of the information required by the proposed rule might expose publicly held utilities to legal liability under the Federal securities statutes. Two concern appear to be involved. The first is that some of the material elicited by the proposed rule may be more conjectural and more speculative than is normally permissible under the securities laws. The other is that the public release of information of this sort may engender special difficulties when public offerings registered under the Securities Act of 1933 are being made or are about to be made.

These concerns stem from the commentators' interpretations of certain past pronouncements by the Securities and Exchange Commission (SEC). However, it is hard to imagine that those pronouncements were ever intended to suggest that compliance with one Federal law would result in the violation of another. Moreover, the comments in question are flawed by their failure to take account of the Securities and Exchange Commission's present position with respect to projections and related topics.

That position is stated in *Guides for Disclosure of Projections of Future Economic Performance*, Securities Act Release No. 5992, Securities Exchange Act Release No. 15305 (November 7, 1978), which points out that filings of the type here involved are compatible with the securities laws but that an affected issuer must, of course, be always mindful of its "obligation to assure the material facts concerning its financial conditions are promptly and fully disclosed and that the information submitted does not become misleading by virtue of subsequent events."[36]

The above-mentioned release also states that the SEC's prior position that section 5 of the Securities Act "would prevent issuers in registration from making projections or including them in their filings * * * is superseded.

What has thus far been said does not mean that the Commission regards the commentators' concerns as frivolous. The securities statutes embody basic public policies, but the policies can easily be reconciled with those reflected in PURPA and in this regulation.

To effect that reconciliation, the Commission suggests that filings made with it and with the Securities and Exchange Commission make appropriate note of the limitations of the material filed in response to the requirements of Part 290.

The Commission notes that the SEC is in accord with this view. Attention is directed to footnote 27 in that agency's aforementioned release of November 7, 1978 which reads:

> In this regard, issuers may wish to consider the appropriateness of clearly distinguishing such information from any projections already made, or clearly indicating that the information should not be considered as a projection for any purpose other than consideration by the requesting authority. In this connection, issuers may also wish to consider the appropriateness of filing a report on form 8-K, 17 CFR 249.308, under item 5, in which the furnishing of this information could be disclosed and the purpose of its submission and nature of its use clarified.

§ *290.301 General instructions for reporting marginal cost information.*

The proposed regulations required that estimates of future costs be reported in constant year dollars. Two private utilities [37] requested that the regulations provide the option of reporting future costs in either constant (base year) or in current (expenditure year) dollars. They contended that many utilities produce estimates of future operating and investment costs only in current year dollars and that it would be uneconomical for them to revise their planning and budgeting procedures just for purposes of section 133 reporting. We found their argument persuasive and, therefore, have adopted a modified version giving utilities the option of providing future costs in either base year or current year dollars. However, under either option, it will be necessary to indicate the inflation factors used in producing the cost estimates.

One utility [38] observed that the § 290.301(b) requirement that "[a]ll historic costs shall be as recorded" was inconsistent with § 290.304(b)(1) requiring that "extraordinary and non-recurring" expenses be adjusted to typical levels. In light of this comment, this section now requires that historic costs be reported as recorded "except when an adjustment is specifically required."

§ *290.302 Generation cost information.*

The proposed regulations required that data on certain cost and operating characteristics be provided for each existing generating unit and for each generating unit that is expected to come on-line during the next ten years. At least five utilities [39] indicated that some of the data items were generally available only on a plant basis. Several utilities [40] urged that the regulations be revised to allow for reporting at a more aggregated level. The data collected in paragraphs (a) and (b) are intended to be used principally in production costing models. Such models can be used to produce estimates of marginal energy costs and marginal generation capacity costs. Our review of these models indicates that cost and operating data are generally not needed on individual units and that reasonably accurate estimates of system marginal costs can be produced from data relating to groups of units with similar operating characteristics. Therefore, revised regulations allow for the reporting of aggregated information on "groups of generating units with similar operating characteristics." It should be noted that the regulations do not require that the units comprising a group be located at the same site. Where similar units are located at the same site, it may be possible to report the required information on a plant basis.

Several privately owned utilities [41] commented that the proposed regulations seemed to require that the data items listed in paragraphs (a) and (b) be supplied for each year of the ten years following the reporting period. It was argued that such a requirement was unnecessary and burdensome. We have tried to clarify this point in the final regulations. The data for existing generating units will be required only for the reporting period. The data for planned generating units will be required only for the first full year of commercial operation. In the case of existing units, § 290.302(c)(1) requires utilities to describe any changes expected at the time of filing, in engineering, regulatory, or economic conditions (apart from general inflation) that would significantly affect the values of any of the reported data items during the next five years.

More than 15 commentators, including utilities, State commissions and consumer groups,[42] filed detailed technical comments on specific items in paragraphs (a) and (b). The comments pointed out that terms such as "normalized" and "typical operating conditions" were unclear. Some comments cited instances where the wording in the proposed regulation was inconsistent with definitions commonly used in the industry. In response to these comments, a number of technical changes have been made. These changes are described below.

Both a consulting firm and a consulting economist,[43] urged that the number of hours that a unit was connected to load be required as a data item. The consulting firm also suggested that the kilowatt-hour output of each unit be provided. We have adopted both suggestions because such data would provide useful information about a utility's dispatching procedures. We have also adopted the Department of Energy's recommendations for information on start-up costs and fuel use because such information allows for an independent analysis of unit dispatching. This is important because the actual or planned pattern of unit dispatching can significantly affect marginal cost calculations.

We have also added a requirement in § 290.302(c)(2) that the reporting utility provide a description of any economic, engineering or regulatory factors that interfered with merit order dispatching during the reporting period and that are likely to continue to do so in the future. This item was added because we saw evidence that the data items listed in paragraphs (a) and (b) were, by themselves, inadequate to allow someone outside the utility to simulate its operations for costing purposes.[44]

One utility[45] recommended that we limit the data submission on hydroelectric units to peaking hydroelectric units since only peaking units would be relevant to the calculation of marginal capacity cost. We did not adopt this recommendation since it was not intended that the data required in paragraphs (a) and (b) would be used only for the calculations of marginal generation capacity costs. As noted earlier, the information in these two paragraphs might also be used by intervenors to produce independent estimates of marginal energy costs. One commentator[46] urged that the fuel saving component of each planned addition be itemized. We did not adopt this suggestion because there was no indication that the value of this information exceeded the costs that would be incurred in collecting it.

The final regulations contain a new data requirement in § 290.302(e) which requires utilities to list "any publicly available reports, documents and forms containing information about the utility's planned additions to generating or transmission capacity which were supplied within the previous 18 months to regional reliability councils and to State or Federal regulatory agencies." This requirement was included so that intervenors and State commission staffs would be informed of other sources of information that could be useful in making marginal cost calculations.

Paragraph (e) of the proposed regulations requested cost information for a hypothetical minimum cost generating unit. Of the more than ten organizations[47] commenting on this paragraph, almost all indicated that they were uncertain as to what was being requested and, therefore, would have difficulty in complying with the requirement. In the final regulations we have clarified the meaning of this paragraph by using a modified version of suggested alternative language submitted by an economic consulting firm.[48] The suggested version would have required estimates of the net annual cost of expanding capacity for five different types of generating units. In our view, this requirement would be too burdensome. Instead, we have modified the suggestion to require that the net annual cost be estimated only for the generating facility or facilities most likely to be installed by the utility to meet increases in peak demand.

§ 290.303 *Energy cost information.*

Paragraph (a) of the proposed rules would have required utilities to report hourly marginal energy costs for the reporting year and for each of the next five years: in effect, more than 50,000 data items. Opposition to this requirement was virtually unanimous among the thirty seven utilities and State regulatory commissions commenting on this requirement. One State commission[49] recommended requiring data for typical days. Three utilities[50] made similar recommendations. Most of those who commented[51] took the position that good estimates of marginal energy costs by costing period could be derived from a much smaller data base. We concur with that judgment. The regulations have been modified to require estimates of hourly marginal energy costs for certain typical days for the reporting period and for the five following years. The regulations require, in addition, that if a utility has calculated marginal energy costs or system lambdas for hours other than those reported for the typical days, this information be made available upon request. At the request of several commentators,[52] the definition of marginal energy costs have been clarified.

Paragraph (c) of the proposed regulations allowed utilities to provide pool marginal energy costs as an alternative to specific company estimates of marginal energy costs. NARUC and three other commentators [53] all recommended that this information be required in addition to the company's own marginal energy costs. Two utilities [54] indicated that pool marginal energy costs may not always be readily available. We have adopted the NARUC recommendation. It seems clear to us that as more and more utilities move into centrally dispatched pools, the pool operating costs may become the relevant basis for determining company marginal costs. If a pool is centrally dispatched, it is not clear to us how the dispatching can take place in the absence of numbers that equal or approximate marginal energy costs.

Paragraph (f) of the proposed rule required the reporting utility to indicate "hours in which the marginal energy cost is likely to be determined by the price paid for purchased power * * *." Two utilities objected to this requirement because of the difficulty in estimating when such hours will occur. Recognizing that such estimates cannot be made with certainty we had included in paragraph (f) the phrase, "likely to be determined," to indicate that the estimates will necessarily be informed guesses. We see no reason to modify this paragraph in the final regulations.

One utility [55] also urged that the energy adjustments required in paragraph (i) be expanded to specify how losses may vary by the location of the customer within the utility's service area. We view this suggestion as a possible refinement to energy loss calculations and note that there is nothing in our regulations to prevent a utility from making these additional calculations if it believes that such calculations are necessary for estimating marginal energy costs. The same comment applies to any other suggested refinements to data request. Our data requirements were designed to provide a core of information for marginal cost calculations. If a utility believes that better cost estimates can be produced using additional information or refinements to the required information we see nothing in our regulations that would preclude filing such information as supplementary material but see no necessity for further refinement in the regulations themselves.

§ *290.304 Transmission cost information.*

Several major objections were raised to the proposed transmission cost information requirements. More than a dozen utilities [56] objected to the requirement that transmission investment, both historic and prospective, be estimated separating out replacement investments. They indicated that in many instances it is difficult to determine if a particular installation constitutes a new or a replacement investment. Recognizing that some utilities would have difficulty with this calculation, we have revised the regulation to give utilities the option of reporting transmission investment with or without replacement investments.

A second objection concerned our requirements for estimates of transmission investments projected ten years into the future. Many utilities [57] indicated that their planning horizon for transmission investments typically is limited to five years and that any information given beyond five years would simply be a trended extrapolation. We have, therefore, revised our regulations to require only five years of projections. These five years of prospective data combined with the ten years of historic data should be sufficient to permit estimates of marginal transmission capacity costs.

A third major objection concerned the requirement that a system map be provide showing existing and proposed generation sites and transmission facilities. Several utilities [88] objected that disclosure of such information would raise acquisition costs. If this is true, it would be an undesired and unintended consequence of our regulations. To minimize the likelihood of such a result, we have modified our regulations so that a utility need not show the specific location of a planned generating or transmission facility, if it believes that the disclosure of such information would raise acquisition costs.

A fourth objection concerned the requirement that project transmission operation and maintenance expenses be reported by account number. Several utilities pointed out that these projections are usually made by functional area and not by account number. Since in most instances the relevant marginal costs can be calculated from changes in aggregates, we have modified the regulations to allow utilities to report projected operating and maintenance expenses by totals rather than by account number.

A consulting economist [89] recommended that certain additional items of informations be collected: Additions to the transmission system by mile of line and size of line; separation of transmission investment into a demand and energy component; the calculation of payments received from other utilities for transmission services on a cents per kilowatt-hour basis; and the separating out of the AFUDC or CWIP components of transmission investment outlays. We have adopted two of these recommendations. Utilities will be required to report pole miles added at each principal transmission voltage level and to separate out AFUDC. It is our view that this information will be useful in making adjustments to marginal transmission capacity cost calculations. The other recommendations were not accepted because they were either method specific or refinements that go beyond basic data needs.

§ 290.305 Distribution and customer cost information.

Several major objections were made to the proposed distribution and customer cost information requirements. These objections generally parallel those that were made with respect to the transmission cost requirements. More than ten utilities [90] objected to the requirement that the replacement component of distribution plant investment be separated from overall distribution investment, both historically and prospectively. Most utilities pointed out that their records do not show such a separation and that this calculation would require a costly reveiw of thousands of work orders. While information on the non-replacement component of distribution investment may be more useful for marginal costs, it is clearly not worth the cost burden that calculating it would impose on most utilities. We have, therefore, rewritten the regulations to give utilities the option of reporting annual distribution investment without separating out the replacement component.

A second objection related to the requirement that utilities provide five years of prospective information. Almost all utilities commented that the typical planning horizon for distribution investment and distribution operation and maintenance expenses is two to three years. Because it is our impression that projections beyond three years will simply represent extrapolations of existing trends, the regulations have been changed to require only three years of projected data. Futhermore, the projections on distribution operation and maintenance expenses have been modified to allow reporting by totals rather than by individual account number.

The item in this section which generated the most controversy was the request in paragraph (a)(3) for an estimate of a minimum distribution system. Some utilities expressed doubts as to whether such a calculation was relevant for a marginalist approach. One association[61] observed that the concept may be inappropriate for a system with a substantial amount of underground equipment. Two commentators[62] objected that the calculation was specific to a certain method and asserted that the Commission should not endorse that method by including this item as a data requirement. As we indicated in the preamble of the proposed regulations, we believe that Congress did not intend that the Commission adopt or endorse a particular costing method in promulgating regulations under section 133. However, we do not think our inclusion of this item in any way represented an endorsement of a particular approach. The Commission has dropped this item from the regulations on the basis that, at this time, it does not wish to impose this reporting burden on the utilities. The Commission re-emphasizes that this action in no way precludes a utility from performing this calculation if the utility believes that the minimum distribution system concept is relevant to its costing exercise.

Paragraph (a)(5) of the proposed regulations required that estimates be made of the current cost of connecting a new customer to the distribution system for each customer class. Three commentators, including the Department of Energy,[63] argued that these estimates would be too aggregated to be of much use. The regulations have now been modified to elicit somewhat more detailed information.

§ *290.306 Other cost information to be reported.*

Several minor changes have been made in the final regulations as a result of comments received on this section. At the suggestion of one group of utilities,[64] paragraph (b) has been modified to require separation of sales expenses "that can be attributed to specific customers or customer classes. In paragraph (d), a transposition in account numbers has been corrected.

§ *290.307 Annual carrying charge rates.*

The proposed regulation required that the carrying charge rate reflect only four types of cost: Depreciation, return, income and property-related taxes, and insurance. Comments indicated that certain cost components should be dropped and other cost components added. One utility[65] advised that the regulations be written to provide more discretion to the reporting utilities. We have taken that advice and have given utilities considerable discretion regarding the calculation of carrying charge rates in the final regulation while requiring that they document in a clear manner the procedures and assumptions employed in deriving the carrying charge rates.

One commentator[66] inquired as to which agency is the "predominant regulatory authority" when a Federal and State commission are both involved. The term "predominant retail regulatory jurisdiction," which is the term now used in this section, excludes a regulatory body of the Federal government.

§ *290.308 Costing periods.*

The proposed regulation required that costing periods be developed that could be used to implement "time differentiated pricing." One industrial consumer advocate[67] claimed that by including this phrase the Commission had overstepped its statutory mandate by moving from costing to ratemaking. We have removed the term from the final regulations. It should be recognized, however, that the periods used for costing will, in most instances, be the same as the periods used for pricing. At the suggestion of one economic consulting firm,[68] we have added a sentence indicating that costing periods should be designed so as to group together hours of similar cost. We view this as a reasonable general prescription. By including this language, we hope to indicate that seasonal or daily differentials may not be justified when the cost differentials are insignificant.

Subpart D—Load Data

General

Comments on Subpart D of the proposed regulations were plentiful and very constructive, and many changes were made in this subpart to reflect those comments. The changes made were primarily to ease the burden of load research on utilities.

Costs of Load Research

The Commission, from the outset, expressed concern with the costs of compliance with the regulations promulgated pursuant to section 133. The item of major concern was the expenses associated with load research. Consequently, meter manufacturers were specifically invited to participate in the informal public conference held on December 4, 1978. The Commission was interested in obtaining information as to whether the manufacturers would be able to meet additional demand for meters in a time frame which would allow covered utilities to comply with a November 1980 filing date, the state of the art in technology, and the cost of meters and associated equipment. An informative presentation was provided by a representative of one manufacturer.[68]

In addition, in the course of the four public hearings, the Commission solicited from various utility representatives, comment as to the cost of conducting load research to meet the requirements of the proposed regulation. The cost figures provided ranged from $250,000 [69] to $4.5–$6.5 million.[70] Therefore, we have undertaken to minimize these costs, while simultaneously attempting to adhere to the Congressionally prescribed requirements for load data.

The two major changes were made in § 290.403(a), concerning for which electric customer classes load data would be required, and in § 290.403(c), concerning the accuracy standard for sample metering.

Customer groups to be reported

Section 290.403(a) of the proposed rule required load data collection for "each customer class for which there is a separate rate". Several utilities [71] commented that this requirement would require the collection of load data for too many rate classes. Conversely, several consumer groups [72] urged the Commission to require a more extensive breakdown of load data by income and usage levels within rate classes.

The rule as revised in § 290.404 requires in paragraph (a) that utilities report load data on a best estimate basis in 1980 and in each subsequent reporting period for residential, commercial and industrial use classes and for any rate class to which 10 percent or more of the system's retail kilowatt-hour sales are made for any month during the reporting period, other than a group composed in whole or in part of residential, commercial or industrial users. Because data on master metered buildings composed of customers in more than one major customer class would not be useful to the determination of the loads for a single major customer class, the final rule requires utilities to exclude the loads in master metered mixed use buildings from the estimates for major customer class loads.

Paragraph (d) of the final rule specifies certain end uses for which load data are proposed to be required and indicates that the list of end uses will not take effect until the Commission makes a determination either to implement the list as proposed or to modify it. Under paragraph (c), utilities having separate rates for all or some of the specified end uses on December 31, 1980, would be required to report load data for any such rates on a sample metered basis beginning in 1982. Utilities having several separate rates for a single specified end use would be permitted to combine for reporting purposes all rates charged for that single end use, as in the case of a utility that charges different rates to communities because of differences in customer charges or in the initial block.

Utilities that do not have a separate rate applicable to one of the specified end uses would be required to report load data for each of the specified end uses on a best estimate basis in 1982 and on a sample metered basis beginning in 1984, since some time must be given for the utility to survey its customers served under a more general rate and separate out for sampling purposes the specified end-use customers.

The end-use groups for which the Commission proposes to require sample metering are:

(1) Residential space heating.
(2) Residential water heating.
(3) All electric residences.
(4) Commercial space heating.
(5) Commercial space cooling.
(6) All electric office buildings.
(7) Master metered multiple dwellings.
(8) Agricultural or industrial uses of process heat.
(9) Large (over 1,000 kilowatts) electric drive motors used in industry, such as in steel rolling mills.
(10) Irrigation.

The Commission has tentatively selected these end-use categories for separate reporting on a sample metered basis because: They have daily and seasonal variations that might be unpredictable without the aid of load research; they comprise a major portion of a system's on-peak loads; they represent uses frequently served under separate rates (and that presumably represent uses with distinct costs); or they cover the principal loads within each major retail customer class. Comments are specifically requested on whether the end uses identified satisfy these criteria sufficiently well to merit implementation, and, if not, for what other end uses separate reporting should be implemented. Recognizing that utilities must know as soon as possible what groups of end-use customers will require sample metering, the Commission, based on comments received on these categories, will determine by the end of August 1979, if the list of end-use categories to be metered should be implemented as proposed or should be modified in response to information supplied in the comments.

Where only best estimates are required either under paragraph (a) or under paragraph (c), utilities must base such estimates on any sample metering they may have conducted for all or a portion of the customer group.

The Commission has granted an extension in paragraph (e) of § 290.404 until January 1, 1985, for the gathering and reporting of load data on all customer groups not specified as major customer classes or end use categories in § 290.404, to the extent that such data are required to be collect under section 133. Section 290.404 is referenced in several other subparts of the rule specifying what cost calculations shall be made for specific customer groups. The Commission has also granted an extension in paragraph (e) until January 1, 1985, for the gathering and reporting of cost information for all customer groups not specified in § 290.404 and for which section 133 requires the collection of cost information.

The Commission believes that good cause exists to grant such extensions. The Congress was explicit in its mandate to the Commission in section 133. Section 133(a)(1) directs the Commission to collect information on costs of serving each electric consumer class, "including costs of serving different consumption patterns within such class * * *." The Commission interprets this statutory language to mean that cost information must be collected for subgroups of customers within a customer class if these subgroups have different consumption patterns, such as electric space heating within the broad residential class. In order to determine the costs of serving such consumption patterns, the utility must collect load data regarding those subgroups.

Section 133(a)(2) directs the Commission to collect load data for each electric consumer class "for which there is a separate rate. * * *" We believe this means that load data are to be collected both for customers served under a separate, distinct rate schedule as well as for customers served under a distinct rate block within a rate schedule. These data could be used, presumably, to test the cost justification of separate and distinct retail rates and to disclose any cross-subsidies between rate schedules or rate blocks.

In granting the extension in paragraph (e), the Commission is attempting to balance the strict requirements of the statute with the problems inherent in meeting the statutory deadlines for collecting and reporting cost and load information.

The Commission has received many comments concerning the expenditures of time and money which will be necessary for conducting that load research required under section 133 and has been advised that it takes several years to initiate and complete such load research and to analyze load and cost data for reporting purposes. The comments assert that costs of meter equipment and of computer hardware and software, and costs of training personnel are high. We understand that new meter technology is being developed that will utilize solid state mechanisms and that will considerably reduce the expense of sample metering for load research. Because of the advent of this new technology, the Commission is reluctant to impose data requirements which may require heavy investments in existing load research meters that may soon be obsolete. On the other hand, new technology will reduce the costs of billing under time of day rates and make them more cost effective. Thus, it is important to begin to collect load data now as a guide to designing time of day rates for the near future. The Commission feels that the extension in § 290.404(e) represents the best accommodation between these conflicting realities and grants such extension for good cause shown. However, Congress contemplated that the Commission would review and revise its regulations as future conditions such as that rate reform contemplated by Title I of PURPA require. We intend to re-examine these extensions and will make such modifications as such future conditions may warrant.

The Commission considers that collection of sample load data for customer groups served on time of day rates is not likely to carry out the purposes of section 133 and, accordingly, has exempted utilities from gathering and reporting such information. The Commission wishes to permit flexibility in the gathering of such information and will impose only cost reporting requirements for those customer groups.

The Commission has already provided an opportunity for comment on the issue of exemptions for customer groups served under time of day rates in accordance with the requirements of section 133(b) of PURPA. (See discussion of comments regarding § 290.404(g) of the proposed rule.) However, the Commission is now soliciting additional comments on this portion of the final rule and will determine, by the end of August 1979, whether to alter it.

As with all other data requirements in Subparts B, C, D and E, State regulatory authorities are not pre-exempted by this federal action from requiring other data with regard to providing electric service. Utilities also should consider whether they, on their own initiative, should gather more extensive information than is called for by the Commission at this time in order to justify the rates that they apply to different groups of consumers.

Accuracy standard

The second major change from the proposed rule concerns the accuracy standard used for conducting load research. Section 290.403(c) of the proposed rule established a standard of plus or minus ten percent at a ninety-five percent confidence level to be met for each hour of the sample period. Almost every respondent commented on this accuracy standard.[73] Critics indicated that it was too stringent because it would be applied to load data collection for every hour of the year and could be used as the basis for rejecting load data if the standard were not met. There were also objections to the confidence level. As proposed, we believe that the accuracy standard would have required heavy investments in recording meters and translating equipment.

Section 290.403(b) of the final rule makes the three following changes designed to ease the reporting burdens and maintain consistency with standard industry practice for conducting load research:

(1) The accuracy level is now a target to be achieved in determining sample size rather than a standard that could be used for the rejection of load data.

(2) The target applies only to measurement of loads at time of system and customer group peaks rather than for each hour.

(3) The accuracy level has been lowered to plus or minus ten percent at a ninety percent confidence level.

The final rule requires utilities to file a sampling plan along with the initial filing of best estimate load data. If the sampled load data do not reach the target level of accuracy in subsequent filings, utilities will be required to provide an explanation for the deficiency.

§ *290.401(a) Hourly load information.*

The proposed rule specified that load data be reported as total sixty minute integrated demands for each hour of a twenty-four hour period. Several respondents [74] suggested that the data be reported on a fifteen minute or thirty minute integrated basis since these time intervals are generally used for load data collection. The final rule allows the utility the option to report load data on whatever basis it chooses, so long as the pool, system, and class loads are reported using the same integration interval. One comment [75] suggested that utilities be given the option of supplying these data on punched cards or in a computer printout. Since it is the Commission's intention at a later date to prescribe the form in which all of these data are to be reported, no change has been made in the proposed regulations on this particular point.

§ *290.401(b) Separate jurisdictional loads.*

This section in the proposed rule required utilities to report customer class loads separately for each jurisdiction. Several respondents [76] indicated that the reporting should be done only on a state-wide jurisdictional basis. Since it was not the intention of the proposed rule to require separate data for small municipalities having original jurisdiction, such as those that exist in Texas and Ohio, this section was changed to make it clear that the data are to be reported separately by state-wide retail regulatory jurisdictions.

Section 290.404(f) of the proposed rule provided an automatic waiver of the separate reporting requirement, with the consent of the State regulatory agency. Several comments [77] suggested that exemptions be made for separate jurisdictional reporting based on the amount of business done in the jurisdictions, the homogeneity of the classes in the jurisdictions, and the similarity of rates for the two or more jurisdictions.

Section 290.401(b) of the final rule is designed to ease the burden of separate jurisdictional reporting of customer group load data by treating monthly group load data differently from hourly group load data. Under paragraph (b)(2) hourly group load data specified in § 290.403(a)(4) are not to be reported separately by retail regulatory jurisdiction unless at least one of the retail regulatory jurisdictions or unless other parties request the separation. If the retail regulatory jurisdiction requests the separation, it is automatically required; if other parties request it, they must demonstrate that the benefits of the separate jurisdictional reporting outweigh the costs.

Under paragraph (b)(1) monthly load data specified in § 290.403 (a)(1), (a)(2) and (a)(3), are required to be reported by separate retail regulatory jurisdiction unless all of the jurisdictions involved waive the separate reporting requirement. Opportunity for comment on the waiver request will be allowed prior to Commission action. Under paragraph (c) applications for the waiver or for the separate reporting of group load data are to be filed at least two years before the time the data would be required to allow sufficient time for Commission action on the application and to permit utilities required to report by separate jurisdictions time to gather the data. For the 1980 reporting, paragraph (d) permits utilities the option of reporting both the monthly and hourly class load data on either a system-wide or a separate jurisdictional basis.

§ *290.401(c) Master metering.*

The proposed rule defined customers as meters and required separate reporting under § 290.406 for the number of customers served under master meters. Several utilities [78] indicated that identification of those customers served under master meters would create a tremendous burden since separate records are not kept for master metered customers. One comment [79] accurately pointed out that the proposed regulations required no separate load data for master metered customers. The final regulations retain the definition of customers as meters in § 290.406(a)(2), and retain the requirement to report separately the customers served under master meters but only if information as to the number of those customers is available. To the extent that master-metered multiple dwellings remain as a category for which load research is required, the number of these customers will be required to be reported.

§ *290.401(d) Typical day loads.*

The proposed rule required that typical day loads for the system and individual classes be determined by averaging hourly loads for each hour of the week, day or weekend day in each month. One commentator [80] suggested that holidays be excluded from the data to avoid distortion. This suggestion was adopted in the final rules. Several other commentators [81] indicated that the concept of typical day and average day loads needed further definition. The final regulations indicated that either the mean or mode of the hourly loads can be used in determining the typical hourly loads. This change should make it clear that the typical day loads are to be an arithmetic average of the measured loads, rather than an arbitrarily selected "typcial day". In the final rules, this section has been moved to the definition section, § 290.105(e), since the typical day concept is used for cost calculations as well as load data reporting.

§ *290.402 Load information for the total of all customer classes (system load information).*

Paragraph (a) of the proposed rule defines the kilowatt load on the system to be reported by utilities. Several comments [82] suggested that adjustments be made to this requirement, particularly to correct for reciprocal supply arrangements between utilities or for wheeling loads. Since the definition would require that interchange power, as well as any temporary deliveries of emergency power be netted out, no further changed has been made in the definition. Firm loads of the reporting utility would and should be included since system costs are affected by all firm loads. Wheeling loads would not affect *net* generation, so no correction to the definition needs to be made for these loads.

§ *290.402(b) Pool load information.*

In the proposed rule, this section required utilities that are members of a power pool to report load data for the pool as well as for the utility. Several comments suggested that this requirement be eliminated either because it served no purpose or because such information is already filed monthly. [83] The requirement has been retained because marginal costing may be based on pool bulk power facilities rather than on the system bulk power facilities, in which case, load data for the pool will be needed for determining costing periods. Although some historic data are reported on pools, the detail needed for costing, and thus required under these regulations, is not generally available historically.

The proposed rule allowed one utility to report pool load data for all of the other utilities in the pool. That provision has been deleted from the final rule and each utility will now be required to report the load data for its pool. This approach is consistent with the Commission's intent that each of these reports be self contained, and that parties using these data not be required to go elsewhere for the required information.

§ *290.402(c) Historic peak loads.*

The proposed regulation required the annual system peak loads to be reported for each of the previous ten years for the system but not for power pools. Although, as one commentator pointed out,[84] this information is already reported in Form 1, the requirement to report is repeated here consistent with the policy of making reports under section 133 self-contained. Two comments [85] indicated that reporting should be done for winter and summer peaks separately. That suggestion has been incorporated into the final rule. One comment [86] suggested that reporting should be done for power pool as well as system peaks because some marginal costing methods use the growth in pool-wide peak demand rather that system peak demand. Although that is true, marginal generation costing methods tend to use projected rather than historic peaks loads. The projected peak loads on a pool basis are required by § 290.402(e). Although historic peak loads are used to normalize the marginal transmission cost data, marginal transmission costs are not calculated on a pool-wide basis.

§ *290.402(d) Reporting period loads.*

This section indicates what load data are to be reported for the pool or system in the reporting period.

§ *290.402(d)(1) Hourly loads*

In the proposed rule, this section required the reporting of hourly loads for each clock hour of each day. Several utilities [87] suggested that this section should be eliminated since only typical hourly loads as required in paragraph (d)(2) would be needed. Since paragraph (d)(2) is an alternative to (d)(1) and since a reporting utility has the option of supplying one or the other, both paragraphs have been retained in the final rule.

§ *290.402(d)(3) Actual and weather normalized monthly peak loads.*

§ *290.402(d)(4) Actual and weather normalized summer and winter peak loads.*

In the proposed rule these sections required the monthly reporting of pool or system peaks with a separate indication of the summer and winter peaks, and required both actual and weather normalized data to be reported. Many comments [88] indicated that no information should be required for weather normalized peaks because of unreliability of estimates, costs of obtaining the estimates, lack of use, and lack of a consensus regarding normalization methods. Other comments [89] pointed out that the requirements in pararaphs (d)(3) and (d)(4) were redundant.

The final regulations have been changed in two ways. First, the requirement for separate reporting of summer and winter peak loads has been eliminated since these data would be included in the monthly peak reporting. Secondly, monthly peaks are now to be normalized for weather or for other factors affecting loads only if the reporting utility uses normalizing techniques for its own purposes.

§ *290.402(d)(5) Maximum demand at primary and secondary distribution voltages.*

This section in the proposed rule required utilities to provide information on the maximum demand on the distribution system at the primary and secondary voltage levels. Quite a few of the comments [90] indicated that requiring the collection of such data is inadvisable if not impossible because of the costs of extensive metering, the impossibility of measuring such data accurately, and the lack of necessity for gathering such information. Other comments[91] criticized the vagueness of the regulation as written. The final regulations eliminate this reporting requirement, primarily because of the costs associated with measuring the maximum demands on the distribution system. It is the Commission's view that marginal distribution costs can be estimated without requiring the collection of these load data.

§ *290.402(e) Projected load information.*

This section of the proposed rule specified projected pool or system load data to be supplied for each of the next ten years. Several general suggestions were made[92] regarding projected load data: Changing the time period from ten years to five years or to the planning period used by the utility; and requiring such data only for the seasonal peak day hourly loads, seasonal average week day and weekend loads. In the final rule projected load data must be supplied for each of the next five years and for the tenth year.

One comment [93] suggested that this section require the utility to describe the process by which the forecasted load data are determined. Growth rates for kilowatt-hour sales, summer peak and winter peak load are required as part of the reporting; the Commission is reluctant to expand the requirement to require any additional, more detailed explanation of projection methodologies at this time.

§ *290.402(e)(1) Projected load duration curves.*

The proposed rule required that utilities supply the annual projected load duration curves and the duration of the loads in hours at 100, 80, 60, 40 and 20 percent of the peak load. Several comments [94] were received on this section requesting that it be either deleted or modified. Several comments [95] suggested that either load duration curves only, or hours of load only, or load curves only be required. The final rule requires reporting of both the load duration curve and the duration of load. Although an outside party could read the duration of load off the load duration curve, the reporting utility would have more accurate data than could be obtained by reading from the curves. One commentator [96] suggested that load duration curves are no longer used in the industry for capacity planning since the advent of modern digital computers and simulation programs. Although this may be true for some utilities, many small utilities reporting under these final regulations still rely on less sophisticated estimating techniques. These requirements are intended to be minimum reporting requirements; any reporting utility having more detailed or computerized projections of load and profiles is encouraged to file such information in satisfaction of this requirement.

Several comments [97] suggested that the duration of load in hours be expanded between 100 percent and 80 percent of the peak load, since it is important to know with some specificity what the variations are around the peak. In response to these comments, the final rule includes the requirement that utilities supply duration of load at 98, 95 and 90 percent of the peak load, as well as the percentages originally required in the proposed rule.

§ *290.402(e)(2) Growth rates for load duration curve.*

This section of the proposed rule required reporting of the growth rates implied by the projected load duration curves specified in paragraph (e)(1) for total kilowatt hour sales, summer peak load and winter peak load. One comment [98] suggested that the Commission require a description of the reliability which the system planners use to project peak loads. Since any projections are done with varying degrees of reliability, it is not necessary to require such detailed information.

§ *290.402(e)(4) Projected maximum demand on the distribution system.*

The proposed rule would have required utilities to project maximum demands on the distribution system at the primary and secondary voltage levels. Because § 290.402(d)(5) of the proposed rules has been eliminated, this section has also been eliminated. This change is consistent with the requests of several utilities [99] that this section be eliminated because such data are almost impossible to obtain.

§ 290.403 Load information for individual customer classes.

In addition to commenting on the number of customer classes for which load data should be collected, several commentators [100] suggested additional information which should be gathered for each customer group, however defined. That information included the sum by class of each customer's maximum individual demand during the year, during each month, and during the on peak period of each month. Commentators argued that this information could be used to compute diversity factors for the purposes of translating demand costs into demand rates. The Commission has not adopted this suggestion since such data may be needed for pricing but are not needed for costing. If these data are required for determining retail rates, the utilities would be able to supply the raw information from which these sums could be calculated and the State regulatory authority would probably have the power to require these sums in individual cases. In conjunction with those changes discussed earlier on what customer groups are to be reported, the word "class" in this section has been changed to "group" when referring to customer categories for which load data are required. Under § 290.404 load data must be reported for major customer classes as well as certain end-use customers. The wording change in this section is intended to be a generic identification for both of these customer categories.

§ 290.403(a)(1) Class maximum demands.

The proposed rule required the utility to report the class maximum demand, in kilowatts noncoincidental with the system peak. Several comments [101] pointed out that the phrase "noncoincidental with the system peak" would require reporting class loads for the next peak hour if those class loads were indeed co-incident with the peak. The final regulations require the maximum demand for the group without further elaboration; thus maximum demands, either coincident or noncoincident with the system peak would be reported.

§ 290.403(a)(2) Class contributions to jurisdictional peak.

The proposed regulations required the utility to report the class contribution to the monthly jurisdictional maximum demand. Several comments [102] indicated that this requirement should be deleted because generation and transmission resources serve the entire system not just a particular retail jurisdiction. Although this comment is correct, group contributions to jurisdictional maximum demands may be used to separate costs between jurisdictions for the purposes of determining the group revenue requirements. Therefore, this requirement is retained in the final regulations.

§ 290.403(a)(4) Hourly class loads.

The proposed regulations would have required the utility to report hourly class loads for a typical week day, weekend day, the class peak day, the jurisdiction peak day and system peak day. Several comments [103] were received on this section, primarily concerning the definition of "typical" and the need for clarification. Since typical days are now defined in § 290.105(e), the only change that was made in this section of the final rule was to delete the requirement for reporting hourly class loads for the jurisdiction peak day. Under § 290.401(b)(2) a utility would not be required to report these hourly loads by separate jurisdictions unless the Commission approved an application for separate jurisdictional reporting. This change is discussed more completely under § 290.401(b) above.

§ *290.403(b) (1), (2) and (3) Use of estimated information.*

This section in the proposed rule permitted utilities to report class load information through the use of estimation techniques that could be based on sample metering, except where load estimates with comparable accuracy could otherwise be made. The purpose of this section had been to make clear that sample metering, not universal sampling, was required, except in those cases where estimates of loads could be made without metering. In the final regulations, this section has been eliminated The final regulations require, on a best estimate basis, load data for major customer classes. Sample metering is required only for specified end uses. Estimates of loads are allowed as part of the "best estimate" of major class loads and need not be separately provided for further in the rules. An extension until 1985 has been provided for the collection and reporting of load data for rate classes not falling within the specified end-use categories or within the definition of major customer class. Thus estimates of loads for these groups are not longer needed. Paragraph (b)(3) of the proposed regulation had required a description of the sampling method used by the utility. This requirement is retained in § 290.403(c) of the final regulation.

§ *290.403(c) Accuracy standard.*

In the final regulation, this section has been changed to 290.403(b). The substance of the changes has been discussed above.

§ *290.403(d) Load research conducted every 5 years.*

The proposed rule allowed utilities to use historic test load data in reporting estimated load data for the current period. The historic test load data could be collected during any period as long as the data were no older than five years. Several utilities[104] commented that the regulation was beneficial because it allowed rotational metering for measuring loads. Other commentators, including one public utility commission,[105] criticized the regulation because, in encouraging rotational metering, it would have discouraged ongoing load research. Several consumer groups[106] objected to the regulation because load research as old as four to five years would be stale and would not reflect any customer response to a rate change that had taken place in the interim.

The Commission believes that rotational metering may serve a useful purpose, especially for smaller utilities that do not have the capability for purchasing meters for each customer group for which load data are required.

Therefore, the final regulation allows rotational metering for any utility with less than one billion annual kilowatt-hour retail sales. For these utilities, actual test data need not be gathered for any particular customer group any more frequently than once every five years. This means that for such utilities reporting in May 1982, group load data collected in any year over the period 1977 to 1981 could be used as the basis for 1981 load estimates. Similarly, for the 1984 filing, load data collected in any year from 1979 to 1983 could be used as the basis for the 1983 load estimates.

Several comments[107] indicated that the regulations improperly imposed the class load factor methodology for translating test load data into current estimated load data. The final regulations delete that specified methodology and leave the choice of estimating technique to the reporting utility.

§ *290.404 Certain exemptions from reporting load information by individual customer classes.*

This section in the proposed rule provided five blanket exemptions and two applied-for exemptions from the requirements that load data be provided for "each customer class for which there is a separate rate." These exemptions were designed to ease the burden of sampling each and every rate class that a utility might have. Since the final rule requires that data be reported on a sample metered basis only for a limited number of specified end uses, many of the exemptions provided for in this section have been eliminated.

Other than the provision for use of borrowed data in 1980, § 290.405 of the final rules provides that the remaining exemptions in this section will now be allowed only after application under § 290.601. Other exemptions may also be requested under the procedures specified in § 290.601.

§ 290.404(a) Combined reporting of class load information.

The proposed rule allowed the utility to combine two classes for the purposes of reporting customer class load data so long as the load imposed by at least one of these classes was less than five percent of the system's daily or annual peak and so long as the two classes being combined were not both major retail classes. The purpose of this exemption was to eliminate the requirement for separate sample metering of non-major, small rate classes. Several commentators[108] noted that a utility could not determine which classes imposed loads of less than five percent until load research had been conducted and suggested that the limitation be expressed in terms of kilowatt-hours of consumption rather than demand. One comment[109] indicated that the exemption should not be extended to fast growing classes. Others suggested that the exemption either be further limited or eliminated. For instance, two comments[110] suggested that combinations should only be permitted for classes with similar voltage levels and load pattern characteristics and that the exemption should not be a blanket exemption. The extension granted in § 290.404(e) of the final rule until 1985 for all customer groups not specified in § 290.404 (b) or (d) covers many of the groups which had been covered by the exemption in § 290.404(a) of the proposed rule. Absent a showing under Subpart F, the Commission has determined that information on the groups not covered by the extension should be reported. Thus the blanket exemption has been eliminated from the final rules.

§ 290.404(b) Exemption for hourly load information.

This exemption, included in the proposed regulations but eliminated in the final regulations, would have exempted utilities from reporting hourly class load data for any class combined under the proposed exemption in § 290.404(a). Again, since the final regulations grant an extension for reporting load data for many of these rate classes, this exemption would be meaningless if retained.

§ 290.404(c) (1) and (2) Provisions for exemption from accuracy standard.

§ 290.404(d) Support for borrowed information.

§ 290.404(e) Applicability of borrowed information.

In the proposed regulations, the exemption in § 290.404(c) from the accuracy standard applied if a particular customer class load could be determined from methods not dependent on direct measurement or sampling. Since the accuracy standard has been changed to an accuracy target, this exemption has been eliminated in the final rule.

The second portion of this blanket exemption allowed a utility to borrow load data from a similarly situated utility for purposes of determining its own load data. Sections 290.404(d) and 290.404(e), described what support the utility would be required to supply for the borrowed load data and what adjustments the utility would have to make to the borrowed load data to insure its applicability to its own class loads. Several commentators[111] endorsed the concept of this blanket exemption. Others[112] indicated that borrowing data is not a viable alternative to gathering load data for a specific system. Several comments[113] suggested that rigorous analysis of transferred data would be necessary prior to use of this exemption, and that the burden of evaluating comparability should be borne by the utilities using the data, not intervenors. Section 290.405(a) of the final regulation allows the use of borrowed load data only for the initial filing in November 1980, which is to be made on a best estimate basis. A utility may not use borrowed load data in any subsequent filing absent an exemption for use of borrowed load data granted pursuant to the procedures in § 290.601.

§ *290.404(f) Waiver of reporting requirement for retail jurisdictional loads.*

The proposed regulations allowed retail jurisdictions to waive the requirement for separate jurisdictional reporting of class load data. Several comments [114] suggested that granting of this blanket exemption not be made contingent on concurrence by the State regulatory authority or, in the alternative, that concurrence be required only if the total retail sales in the jurisdiction for the reporting year are less than 500 million kilowatt-hours or do not exceed five percent of the system's daily annual peak. One commentator [115] suggested that those State regulatory authorities consenting to the waiver should be required to specify the allocations that would be used among jurisdictions for splitting the revenue requirements. Another commentator [116] suggested that safeguards be included to assure an opportunity for interested parties to be heard before any waiver of jurisdictional reporting of load data was allowed. Since section 133 does not require separate jurisdictional reporting, an exemption to the statute is not needed and this blanket exemption has been eliminated in the final regulations. Waivers to that separate jurisdictional reporting required by these final regulations will be permitted under those conditions specified in § 290.401(b), discussed above.

§ *290.404(g) Exemption based on extension of time.*

The proposed regulations granted a one year exemption from filing hourly class load information if the utility applied for a rate increase during the one year extension period provided in § 290.405 of the proposed regulations. Since filing of load and cost data is not mandated in section 133 at the time of a rate increase and has not been required under the final rule, this exemption is unnecessary and has been eliminated in the final rules.

§ *290.404(h) No exemptions for major classes on time of use rates.*

The proposed rule allowed no exemptions for any rate class served under a time of use rate. Almost all of the utilities [117] commenting on this section felt that this exception to the general blanket exemptions was inadvisable. Some were concerned that it could present a disincentive to utilities to engage in time of use pricing. The final regulation eliminates this section of the proposed rule. It should be noted, however, that the Commission intends to further consider by the end of August, 1979, whether the utilities having customer groups served under time of day rates are exempted from collecting load data by sample metering. (See the general discussion at the beginning of this subpart.)

§ *290.404(i) Exemption if the customer class is to be changed.*

The proposed regulation exempted utilities from separately reporting any rate class that was to be combined with another class of customers or was to be otherwise drastically altered. The single comment [118] on this section suggested that it be eliminated because it removes the requirement that necessary data be gathered concerning similarity of load characteristics for the rate classes to be consolidated. Since the Commission has required in the final regulation that load information be collected for specified end uses, whether or not there is a separate rate, this exemption has been deleted.

§ *290.404(j) Exemption for joint load research.*

The proposed regulations allowed any group of utilities intending to engage in joint load research to apply to the

Commission for an exemption from the requirement that each utility report system and class load data separately. Several comments[119] suggested that the Commission require evidence of comparability of class loads before granting this exemption. Other comments[120] suggested that the Commission conduct a major research study to determine load characteristics of retail loads that could be used by other utilities or establish joint regional committees to conduct joint load research. One commentator[121] indicated that the exemption should apply to generation and transmission cooperatives and their member distribution rural electric cooperatives. Several comments[122] were received suggesting that the TVA be permitted to undertake joint research for all of its distributors and to report such information in a consolidated report. (See the discussion concerning § 290.102(c).) This provision has been retained in § 290.405(b) of the final rule. As in the proposed rule, this provision is not a blanket exemption but must be applied for under § 290.601 on a case-by-case basis.

§ *290.405 Extension for reporting hourly load information by individual customer classes.*

This section in the proposed rule provided for an automatic one year extension beyond November 1980 for the reporting of hourly class load data if the utility certified that it had not commenced a program for the collection of hourly class load data by means of sample metering and had not been ordered to collect such data by any other regulatory authority at the time PURPA was enacted. Several suggestions[123] were made changing the time frame from two years to five years to "a reasonable time". Several comments[124] suggested that the extension should apply even if the State regulatory authority had not ordered the utility to conduct load research; i.e., even if the utility had already begun to conduct such research on its own. Other commentators[125] suggested that the term "commenced a program" was unclear. The extension has been eliminated from the final regulations since no new load research will be required in 1980 for reporting of the best estimate loads for the major customer classes.

§ *290.406 Other information to be reported.*

This section required additional information to be reported on customer classes, loss factors, and on other items affecting load data collection.

Two comments[126] suggested that a new paragraph be added to this section to require submission of bill frequency data in order to permit development of block rates and to determine the effect of these rates on the distribution of revenue responsibilities by class, by tariff schedule and by individual customers or groups of customers within a tariff schedule. It is the Commission's view that these data would generally be available from the reporting utility in any rate design proceeding, and the suggestion has not been adopted in the final regulation.

§ *290.406(a) Assumptions used and description of weather normalization techniques.*

The proposed regulations required the utility to describe the parameters used for weather normalization as reported under §§ 290.402 and 290.403. In the final regulations, weather normalization or normalization of loads for other factors is required only if the utility already makes those calculations for peak loads. If normalization techniques are used, a description and demonstration of the technique are required under § 290.402(d)(3) of the final regulations. Therefore, separate reporting of this information is not required as a general matter, and this paragraph has been eliminated.

§ *290.406(b) Information on individual customer classes.*

Paragraph (b)(1) of the proposed regulations required utilities to provide information on energy sales for each month in the reporting period for each customer class for which load data were collected under § 290.403(a). One commentator [127] suggested that a new section be added requesting energy sales for given time periods and voltage levels so that average costs by time of use could be assigned. Since a requirement has been added to Subpart B, Accounting Cost Information, for the utility to calculate average energy costs by time of use, collection of those data here would not be necessary, and the final rule has not been changed in this regard. Another commentator [128] suggested that the requirement include data for each of the previous nine years as well as for the reporting period. Since the load data by customer groups would only cover the reporting period, customer group information has similarly been limited to the reporting period. The data to be collected under this section refer to customer groups identified in §§ 290.404 (b) and (d). This section is now § 290.406(a).

§ *290.406(b)(2) Number of customers.*

This section required reporting of the number of customers at the end of the reporting period. One commentator [129] suggested that both number of customers as well as monthly energy sales should be supplied by voltage level. Since loss factors for energy sales are required under § 290.406(b) of the final regulations and since the number of new customers by principal delivery voltages is required under § 290.406(a)(3) of the final regulations, the number of customers and sales by voltage level could be calculated and further reporting of the number of customers or energy sales by voltage level would be unnecessary. The number of customers is to be reported in § 290.406(a)(2) of the final regulations.

§ *290.406(b)(3) New customers by voltage level.*

This section of the proposed rule required utilities to report the number ot new customers by primary, secondary and transmission voltage levels for the reporting period and for each of the previous five years. Several commentators [130] indicated that information on new new customers could not be supplied since those data currently were unavailable, that the burden of obtaining them would be onerous, and that, especially for historical information, the number of new customers would be practically impossible to reconstruct. The final regulations have been changed to reflect these comments and to require the reporting of the number of new customers only if available. Net change in customers is required under § 290.406(a)(3) of the final regulations if data on new customers are not available.

§ *290.406(c) Loss factors.*

In the proposed regulations, this section required the utility to report the estimated loss factors both for energy and demand resulting from the transmission of electricity to principal delivery voltage levels. Several comments [131] indicated that the regulation was too burdensome. Nevertheless, the requirement is retained in the final regulations since these loss factors may be estimated by the reporting utility and do not have to attain a level of accuracy that would require metering at various points on the transmission and distribution systems.

§ *290.406(d) Effective date of rate changes.*

In the proposed regulations, this section required the utility to report the effective date of a rate change and the approximate date on which bills were first received under the new rate. A similar requirement was imposed if an automatic adjustment clause resulted in a rate adjustment of more than ten percent of the previous month's rate. Several commentators [132] indicated they have no information on when bills were received because they bill cyclically. Others indicated that the requirement regarding automatic adjustment clauses was irrelevant. Although it would be useful for parties using the load data to have some information concerning price changes during the period in which load data were being collected, this information can be obtained by other means and the provision has been deleted from the final regulations.

§ 290.406(e) Shifts on and off daylight saving time.

This section required that utilities report the hour, day and month of shifts on and off daylight saving time and the time zones in which the retail loads are located. No comments were received on this section.[133] The final regulations retain the requirement as § 290.406(c).

Subpart E—Calculated Costs

This subpart required utilities to calculate both accounting costs and marginal costs by costing period, customer class, and voltage level in summary tables similar to those included in the regulation. The proposed rule required that such tables be completed for each jurisdiction in which the utility operated unless the utility could show that the jurisdictional cost variation was not significant. If a method for calculating either marginal or accounting costs has been specified by State law or the State regulatory authority, the regulations required that the calculation method used by the utility be consistent with that method. The regulations also required that the reporting utility describe the method used for the calculations and provide a copy of any cost study upon which the calculations in the table were based. As an alternative to completing the tables, the proposed rule provided that the utility may provide a recent cost of service study (fully allocated and marginal) provided that such study included all the information specified in the tables and in Subparts B and C, respectively.

§ 290.501 Accounting cost calculations.

The alternative for providing a cost of service study has been eliminated from paragraph (d) of both § 290.501 and § 290.502 of the final rule. Provisions for alternate submissions of information are now contained in § 290.103(c) of the final rule. The only major change in § 290.501 has been the inclusion in paragraph (b) of accounting cost requirements previously contained in Subpart B.

§ 290.502 Marginal cost calculations.

The proposed regulations required utilities to estimate the marginal costs of providing service by costing period, customer class and voltage level for each State jurisdiction in which the utility operated, unless it could be shown that the jurisdictional variation was not significant. One utility [134] urged us to allow for the reporting of costs on a system wide basis, without a prior showing that jurisdictional variation was insignificant. One commentator [134a] concurred, arguing that the regulation incorrectly presumed that marginal costs will typically vary by jurisdiction and observing that, "[t]he real economic (marginal) costs of providing service are incurred at the system (or the pool) level and are the same at the margin for all jurisdictions at the same point in time. What will vary among jurisdictions is the allowed rate base, expenses and rate of return, thus leading to differences in total revenue constraints." We have reviewed a number of marginal cost studies and found that jurisdictional boundaries were generally deemed irrelevant for the calculation of marginal costs. Therefore, the regulations have been changed to require the calculation of marginal costs for the "system as a whole".

One commentator [135] recommended that Table 2 should also include an estimate of the total amount of revenue that would be generated if the calculated cost components were implemented as billing determinants. We did not adopt this proposal for two reasons. First, it might lead to the false impression that marginal costs can be directly translated into time differentiated rates. We think it is clear that requiring marginal cost calculations does not necessarily imply that prices should be equivalent to marginal cost. A second consideration is that the adoption of this recommendation would extend the regulations unnecessarily into the sphere of ratemaking whereas the regulations should more properly focus on cost data. We recognize that calculations such as those proposed will eventually have to be performed but we do not think such calculations should be required under the regulations implementing section 133.

NARUC and several other commentators [136] observed that the illustration table conveyed the impression that "off-peak" hours could not carry any marginal capacity costs. This was an oversight on our part. Table 2 has been revised to show that off-peak hours do have the potential for carrying some capacity costs.

Subpart F—Exemptions and Extensions

§ *290.601 Exemptions.*

The proposed rule required that utilities submit exemption applications one year prior to the time the filing is required. The Commission deemed this period necessary for allowing time for notice, comment, analysis, and Commission action but now feels that an additional six months lead time is required if utilities denied an exemption are to have adequate time to supply the necessary information. It should be clarified that a utility need submit only one application for each filing year for which it seeks a partial or total exemption.

The proposed rule also required that utilities seek review of such applications by State regulatory authorities and permitted State regulatory authorities to apply for exemptions for utilities under their jurisdiction. NARUC suggested an alternative to the proposed procedure that would involve a compliance plan to be developed by utilities and approved by State regulatory authorities prior to its submission to the Commission for approval. [137] The Commission has considered this suggestion carefully. Although the final rule does not explicitly include this suggestion, the State regulatory authority will have an opportunity to review any request for exemption and to comment on it to the Commission. The final rule contains a specific provision requiring applications for exemption to be filed with this Commission and with the State regulatory authority no less than eighteen months prior to the time the information would otherwise be required to be filed. A State regulatory agency may, on its own authority, require a utility to provide the application for exemption to it at an earlier time than that required in the regulation. Also a State regulatory authority may, under State law, continue to require information to be filed with it even though the Commission grants an exemption.

There were several comments suggesting that authority to grant exemptions to the filing requirements be delegated to State regulatory authorities. [138] We do not believe that the statute gives the Commission authority to make such a delegation. However, the various State regulatory agencies can provide a very important contribution by evaluating applications for exemptions. The rule acknowledges this function by requiring utilities to submit applications for review at the State level. Through this requirement we intend to place principal reliance for such evaluation on the State regulatory authorities.

We have amplified on the specific information necessary to support applications for exemption. We believe this expansion is an improvement on the proposed rule in that it makes certain distinctions among basis for exemptions, and indicates the nature of the information that the Commission will require in reviewing each type of exemption.

A large number of small utilities submitted comments that were really requests for exemption. These requests were based either on the size of the utility or on the utility's receiving all of its power through purchase from another utility. [139] The Commission considers these requests to be premature and has not considered their merits relevant to each applicant. If these utilities seek exemptions from provisions of the final rule, they must file new applications in accord with the requirements of the final rule. It should be noted that a number of the utilities that requested exemption on the basis of size will qualify for the special extension for small utilities provided in § 290.102(d) of the final rule.

Both the Department of Agriculture, Rural Electrification Administration (REA), and the National Rural Electric Cooperative Association suggested that specific exemptions be established for REA borrowers because these cooperative utilities already file substantial cost information with REA. The Commission finds that the cost information required under this rule is substantially different from that filed with REA by its borrowers. Therefore, the utilities' compliance with REA requirements is not an adequate substitute for filing the cost information required here. However, there may be other reasons for exempting certain of the cooperative utilities from the requirements of these regulations which will be considered upon application pursuant to the exemption provisions of the final rule. Meanwhile, many of these cooperatives will qualify for the special extension provided in § 290.102(d).

§ *290.602 Extensions.*

The proposed rule provided an application procedure for extensions. No substantial comments were received on this section distinct from those concerning the exemption provisions which have already been discussed. The final rule includes changes in this section only to the extent necessary to parallel changes made in § 290.601 governing exemptions. In granting extensions either through the mechanism established in this section or in such blanket extensions as are embodied in the final rule, the Commission intends that a utility not be required to file at any later time the information which it would otherwise have been required to report during the extension period. The Commission's extension authority under section 133 is limited by section 133(b)(2) to extensions of the initial two year period following the date of enactment.

Subpart G—Enforcement

§ *290.701 Enforcement provisions.*

This section states that any person who violates the requirements of Part 290 shall be subject to a civil penalty of not more than $2,500 for each violation and that any person who willfully violates those requirements shall be fined not more than $5,000 for each violation. This section corresponds to the enforcement provisions in section 12 of the Energy Supply and Environmental Coordination Act of 1974 (ESECA).

Several comments[140] indicated that all sanctions should be limited to willful violations. Two of these commentators[141] indicated that sanctions should not apply to *de minimis* violations. Section 133(d) requires that any violation of section 133 of PURPA be treated as a violation of a provision of ESECA, enforcible under section 12 of that Act. The regulations as promulgated in proposed form adhere to this statutory mandate and will not be amended. In enforcing the requirements of Part 290, the Commission will invoke such sanctions as it deems appropriate.

Written Comments

Although these regulations are being issued in final form, the Commission has specifically requested comments on §§ 290.404(d) and 290.404(f). The substantive provisions of these sections will not become effective absent further determination by the Commission. The Commission intends to act in this regard by the end of August, 1979.

Interested parties are invited to submit written comments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426. Comments should reference Docket No. RM79-6 on the outside of the envelope and on all documents submitted to the Commission.

Fifteen (15) copies should be submitted. All comments and related information received by the Commission before July 15, 1979, will be retained and considered by the Commission prior to any further action on these final regulations.

(Public Utility Regulatory Policies Act of 1978, Pub. L. 95–617, Energy Supply and Environmental Coordination Act 15 U.S.C. 791 *et seq.*, Federal Power Act, as amended 16 U.S.C. 792 *et seq.*, Department of Energy Organization Act, Pub. L. 95–91, E.O. 12009, 42 FR 46267).

In consideration of the foregoing, the Commission amends Chapter I of Title 18, Code of Federal Regulations, as set forth below, effective July 15, 1979.

— Footnotes —

[1] We specifically reject the comments made in a late filing (on behalf of Appalachian Power Company and eleven other utilities) which assert that this final rule violates Executive Order 12044. Executive Order 12044 requires that the public be given at least 60 days to comment on any proposed "significant regulations" and that, if the additional economic impact of the regulations will be equal to or greater than $100 million, the agency prepare a comprehensive regulatory analysis assessing the cost of the program and alternative approaches which could minimize its adverse impact on the economy. Executive Order 12044 does not purport to bind independent regulatory commissions acting as agents of Congress. However, the Commission has acted on its own initiative in full accord with the spirit and intent of this order. Utilities have had full opportunity to comment in the entire rulemaking process (not merely on specific regulations) with full understanding of its foundation and evolution. Moreover, we have sought to ascertain the cost of compliance, and to choose cost minimizing strategies wherever possible. See, for example, the discussion at pages 14 through 16 and 66 and 67. Given the mandatory time for promulgating these rules, the Commission could not submit to a paralysis of analysis that would violate its specific statutory obligations under section 133.

[2] See the comments filed on behalf of the Edison Electric Institute (EEI) and Individual Members of the Utility Regulatory Analysis Program, April 6, 1979, Part II, pages 1 and 3. The same assertion is later reiterated as a subtitle heading "Elementary Rules of Statutory Interpretation do not Permit the FERC to Require Marginal Cost Information under Section 133."

[3] See EEI comments, Part II, page 5.

[3a] See comments of the Public Service Company of New Hampshire at the Cambridge public conference.

[4] Comments of the Florida Public Service Commission.

[5] Comments of the Environmental Defense Fund. The contrary view was advanced by several representatives of low-income interests and by ELCON.

[6] Comments of Detroit Edison Company. See also the comments of Ernst and Ernst.

[7] See the comments of Detroit Edison Company.

[8] See comments of Electrical Consumers Resource Council (ELCON).

[9] Several other organizations representing similar constituencies strongly supported requiring calculations. See, for example, the comments of Legal Aid of Missouri, Prairie State Legal Services, Inc. and the Ohio Association of Community Action Agencies.

[10] See the written comments of Utah Power and Light, Tampa Electric Company, Florida Power Corporation and City Public Service Board of San Antonio, Texas, Massachusetts Electric Co., Public Service of Colorado, Central Power and Light Co., Central and Southwest Corp., Pacific Gas and Electric Co., and Consumers Power Company.

These are necessarily rough estimates, subject to errors in both directions. For example, the estimates may be too low because some utilities may have simply estimated the cost of completing a marginal cost study without taking into account that Subpart B may require data that would not be used in their own marginal cost studies. On the other hand, some of the estimates are probably too high because the data requirements in the proposed version of Subpart B were more extensive than those which will be required in the final version of Subpart B. Furthermore, these are estimates of initial cost. The cost estimates for subsequent filings are, in almost all instances, as much as 50 percent lower.

[11] Most of the commenting parties expressing a preference for utilization of a modified Form 1 cited a concern over the burded of providing duplicative information. The parties favoring modification were: Indianapolis Power and Light, Northern States Power Co., Texas Power and Light Co., Central Illinois Public Service Co., United Illuminating Co., Kansas Gas and Electric Co., Massachusetts Electric Co. and Narragansett Electric Co., Texas Electric Service Co., Carolina Power and Light Co., Climax Molybdenum Co., Northeast Utilities, Florida Power and Light Co., Arkansas Power and Light Co., U.S. Office of Consumer Affairs, El Paso Electric Company.

The commenting parties opposing a modification of Form 1 were: Middlewest Service Company, Florida Public Service Company, West Texas Utilities, Puerto Rico Water Resources Authority, Pacific Power and Light Co., Publicly-Owned Systems, American Public Power Association, Middlewest Services Co., Georgia Power Co., Seattle City Light, Pennsylvania Power and Light Co., Central Louisiana Electric Co., and National Rural Electric Cooperative Association.

[12] See comments made on behalf of Fitchburg Gas and Electric Co., *et al.* See also comments of Savannah Electric and Power Co., and of the American Public Power Association (APPA).

[13] See, for example, comments made on behalf of the Electric Department of the City of Tallahassee, Florida.

[14] The statement of managers in discussing Section 133 states: "The conferees intend that good information with regard to costs of providing service must be readily available on a timely basis to everyone concerned."

[15] See, for example, the testimony of the Hawaiian Electric Company at the March 19, 1979, public hearing held in Seattle. See further discussion of such requests under Subpart F.

[16] Meriwether Lewis Electric Cooperative, Electric Power Board of Chattanooga, and Tennessee Valley Public Power Association.

[17] See, for example, comments of Puget Sound Power and Light Company.

[18] See, for example, comments of the Detroit Edison Company and of the Florida Public Service Commission. Approximately twenty other utilities and commissions made this same suggestion.

[19] See comments of the EEI, Part II, LeBoeuf, Lamb, Leiby and MacRae and others.

[20] See, for example, the comments of the Public Utility Commission of Texas.

[21] See the comments of the Public Service Company of Colorado.

[22] See the comments submitted on behalf of Appalachian Power Co., *et al.*

[23] See the comments of Publicly Owned Systems.

[24] See comments of the New York State Electric and Gas Co. and Central Hudson Gas and Electric Co.

[25] Comments of the Pennsylvania Power and Light Co.

[26] For example, comments of the Philadelphia Electric Co.

[27] For example, comments of Georgia Power Co. and Public Service Electric and Gas (NJ).

[28] For example, Pennsylvania Power and Light Co., and Arizona Public Service Co.

[29] For example, Iowa-Illinois Gas and Electric Co.

[30] For example, Houston Lighting and Power Co.

[31] See comments of Tampa Electric Co. and Northeast Utilities.

[32] See comments of Houston Lighting and Power Co., General Public Utilities Service Corp. and Alabama Power Co.

[33] See comments of U.S. Office of Consumer Affairs.

[34] See comments of EEI and Middle South Services Corp. at the New Orleans hearing.

[35] See comments of El Paso Electric Company, Gulf States Utilities Company and Joint Comment of Public Service Company of Oklahoma, Central Power and Light Company, Southwestern Electric Power Company and West Texas Utilities Company.

[36] The quotation is from the portion of the release captioned "Projections Required by Regulatory Authorities".

[37] See the comments of Carolina Power and Light Co., April 6, 1979 and Gulf Power Co., April 5, 1979.

[38] Alabama Power.

[39] See the comments of Florida Power and Light Co., April 5, 1979, Texas Power and Light Co., April 5, 1979, General Public Utilities Service Co., April 6, 1979, Alabama Power Co., April 6, 1979, and Houston Light and Power Co., April 5, 1979.

[40] See the comments of Pacific Power and Light Co., April 6, 1979, Southern California Edison Co., April 6, 1979, Pennsylvania Power and Light Co., April 6, 1979, Florida Power and Light Co., April 5, 1979, Texas Power and Light Co., April 5, 1979 and Kansas Gas and Electric Co., April 3, 1979.

[41] For example, see the comments of Florida Power and Light Co., April 5, 1979, Appalachian Power Co. et al., April 9, 1979, Southern California Edison, April 6, 1979 and the Massachusetts Electric Co., April 5, 1979.

[42] See the comments of the New England Regional Energy Project, April 10, 1979, Boston Edison Co., April 6, 1979, Ohio Edison Co., April 6, 1979, Arizona Public Service Corp., April 6, 1979, Southern California Edison Co., April 6, 1979, Pennsylvania Power and Light Co., April 6, 1979, California Manufacturers Association, April 4, 1979, Texas Power and Light Co., April 5, 1979, California Public Utilities Commission, April 6, 1979, Ernst and Ernst, April 6, 1979, Department of Energy (Economic Regulatory Administration), April 6, 1979, Appalachian Power Co. *et al.*, April 9, 1979, Kansas Gas and Electric Co., April 3, 1979, Eugene Coyle, Ph.D., April 2, 1979 and National Retail Merchants Association, April 6, 1979.

[43] Ernst and Ernst and Eugene Coyle, respectively.

[44] See page 39 of the transcript of the Kansas City, Missouri hearing held March 15, 1979.

[45] Southern California Edison Company.

[46] Los Angeles Water and Power District.

[47] Among the commentators who suggested or requested clarification were the New England Regional Energy Project, April 10, 1979, Texas Public Utilities Commission, March 29, 1979, Ohio Edison Co., April 6, 1979, Los Angeles Power and Water District, April 9, 1979, California Public Utilities Commission, April 6, 1979, National Economic Research Associates (NERA), April 6, 1979, El Paso Electric Co., April 6, 1979, Arkansas Power and Light Co., April 6, 1979 and Utah Power and Light, April 6, 1979.

[48] NERA.

[49] Texas Public Utilities Commission.

[50] Public Service of Colorado, Massachusetts Electric and Carolina Power and Light.

[51] See the comments of the Detroit Edison Co., April 5, 1979, Ohio Edison Co., April 6, 1979, Public Service Co. of New Mexico, April 10, 1979, Carolina Power and Light Co., April 6, 1979, Massachusetts Electric Co., April 5, 1979 and Pennsylvania Power and Light Co., April 6, 1979.

[52] This request was made by Appalachian Power Co. *et al.*, April 9, 1979, El Paso Electric Co., April 6, 1979 and the Department of Energy (Economic Regulatory Administration), April 6, 1979.

[53] The New England Regional Energy Project, the Michigan Department of Commerce and the California Public Utilities Commission.

[54] Consolidated Edison and Baltimore Gas and Electric.

[55] El Paso Electric Co.

[56] See for example, the comments of the Boston Edison Co., April 6, 1979, Georgia Power Co., April 6, 1979, Appalachian Power Co. *et al.*, April 9, 1979, and Mississippi Power Co., April 5, 1979.

[57] In particular, see the comments of Public Service Co. of Colorado, March 26, 1979, Georgia Power Co., April 6, 1979, Consolidated Edison Co., April 6, 1979, Wisconsin Power and Light, April 6, 1979 and NARUC, April 6, 1979.

[58] See, for example, the comments of Texas Power and Light.

[59] Eugene Coyle.

[60] For example, see the comments of Gulf Power Co., April 5, 1979, Alabama Power Co., April 6, 1979, Iowa-Illinois Gas and Electric Co., April 5, 1979 and Southwestern Power Co. *et al.*, April 6, 1979.

[61] APPA.

[62] The New England Regional Energy Project and Eugene Coyle.

[63] See also the comments of the New England Regional Energy Project and Louisiana Power and Light.

[64] Appalachian Power Co., *et al.*

[65] Wisconsin Electric Power.

[66] Comments of Public Service Company of Colorado.

[67] ELCON.

[68] NERA.

[69] See the Statement of Mr. William F. Dewire, Westinghouse Meter Division, Tr. pp. 64–91.

[70] See the written comments of Hawaiian Electric Company.

[70] See the written comments of Massachusetts Electric Company and Narragansett Electric Company.

[71] See, for example, Kansas City Power and Light, testimony at the Kansas City, Missouri hearings, wherein it was said that 150 to 200 rate schedules would be subject to load collection under the proposed regulations.

[72] See, for example, the filing by the National Consumer Law Center, Inc., Missouri Legal Aid and Prairie View Legal Services. See also, the comments of El Paso Electric.

[73] See, for example, the comments of the Load Research Committee of the Association of Edison Illuminating Companies.

[74] See, for example, comments of Consolidated Edison of New York, New England Regional Energy Project, Public Service Company of New Hampshire, Eugene Coyle.

[75] General Public Utilities Service Corp.

[76] NARUC, the California Public Utilities Commission and several utilities commented on the jurisdictional reporting requirement. Particularly, the utilities in Texas and the State PUC and Attorney General pointed out that primary retail rate jurisdiction lies with municipals in the State. See Subpart A for further discussion on this point.

[77] For example, General Public Utility Service Corp. and Pacific Power and Light Co.

[78] For example, Houston Lighting and Power, Public Service of Colorado.

[79] Public Service Electric and Gas.

[80] Southern California Edison.

[81] For example, the Department of Energy, Economic Regulatory Administration.

[82] Texas Public Utility Commission and Department of Energy.

[83] United Illuminating and Pacific Power and Light.

[84] Michigan Public Service Commission.

[85] New England Regional Energy Project and Missouri Legal Aid.

[86] Department of Energy.

[87] For example, Florida Power and Light and United Illuminating.

[88] For example, Consumer Power, Carolina Power and Light, Indiana Power and Light Company, APPA.

[89] For example, Toledo Edison, Hawaiian Electric Company.

[90] For example, AEIC, Public Service Co. of New Hampshire.

[91] For example, Michigan Public Service Commission, Northern States Power Co.

[92] See, for example, the comments of Southern California Edison and Eugene Water and Electric Board.

[93] Department of Energy.

[94] For example, Michigan Public Service Commission, United Illuminating.

[95] For example United Illuminating Company of New Haven.

[96] Hawaiian Electric Co.

[97] For example, California Manufacturers Association, California Public Utilities Commission.

[98] California Public Utilities Commission.

[99] For example, Central Maine Power Co., United Illuminating, Texas Power and Light Co., Kansas Gas and Electric Co.

[100] For example, NERA, Department of Energy, ELCON.

[101] Carolina Power and Light, Hawaiian Electric Co., Association of Edison Illuminating Companies (AEIC).

[102] For example, Southern California Edison Co.

[103] For example, Missouri Public Service Commission.

[104] For example, Seattle City Light, Alabama Power Co., El Paso Electric Company, Massachusetts Electric and Narragansett Electric Company.

[105] Missouri Public Service Commission, Kansas City Power and Light, Indiana Power and Light Company.

[106] For example, National Consumer Law Center, New England Regional Energy Project.

[107] For example, Carolina Power and Light, AEIC.

[108] For example, Iowa Southern Utilities, NARUC, California Public Utilities Commission.

[109] Public Service Co. of Colorado.

[110] ELCON and Eugene Coyle.

[111] For example, Public Service Co. of Colorado, City of Santa Clara, California, Toledo Edison Co.

[112] For example, El Paso Electric Co., Eugene Coyle, Carolina Power and Light Co., Indianapolis Power and Light Co.

[113] For example, Kansas City Power and Light Co., Missouri Legal Aid.

[114] For example, Wisconsin Power and Light Co., Public Service Co. of New Hampshire.

[115] National Retail Manufacturers Association.

[116] Department of Energy.

[117] For example, Texas Electric Service Co., Consolidated Edison of New York.

[118] Texas Public Utilities Commission.

[119] For example, National Retail Manufacturers Association, Department of Energy.

[120] For example, Publicly Owned Systems, National Rural Electric Cooperative Association.

[121] Rural Electric Administration.

[122] For example, Electric Power Board of Chattanooga, Tennessee Valley Public Power Association.

[123] For example, Public Service Company of Oklahoma, Iowa Southern Utilities Co.

[124] For example, Texas Power and Light Co.

[125] For example, Kansas Gas and Electric Co.

[126] Department of Energy and Eugene Coyle.

[127] ELCON.

[128] Ernst and Ernst.

[129] ELCON.

[130] For example, City Public Service Board of San Antonio, Texas and United Illuminating.

[131] For example, Public Service Co. of Colorado, Puerto Rico Water Resources Authority.

[132] For example, Louisiana Power and Light Co., Northern State Power Co.

[133] In this regard, this section is unique.

[134] Houston Power and Light Co.

[134a] Department of Energy.

[135] EEI.

[136] See, for example, comments of Massachusetts Electric Co., Wisconsin Electric Power Co.

[137] See also the comments of the Texas Public Utility Commission and the Michigan Public Service Commission.

[138] See the comments of Hawaiian Electric Company and Texas Electric Service Company.

[139] The comments filed on behalf of the Electric Department of the City of Tallahassee, Florida, and of the City of Wilson, North Carolina, Department of Utilities, are representative.

[140] See comments of EEI, Southern California Edison Co., Pennsylvania Power and Light, Houston Lighting and Power Company, and Fitchburg Gas and Electric, *et al.*

[141] See comments of EEI and Pennsylvania Power and Light Co.

[¶ 30,058]

44 F. R. 34472 (June 15, 1979)

18 CFR Part 270

[Docket No. RM79-22; Order No. 23-A]

Regulated Sales of Natural Gas; General Rules and Definitions

AGENCY: Federal Energy Regulatory Commission.

ACTION: Interpretive rule.

SUMMARY: Although the Natural Gas Policy Act of 1978 (NGPA) sets maximum lawful prices for first sales of natural gas, the NGPA does not supersede or nullify the effectiveness of the price established under existing contracts. This interpretive rule states that the NGPA does not prohibit the amendment of an existing contract to collect any applicable NGPA rate.

DATES: Effective June 12, 1979.

ADDRESSES: All filings should reference Docket No. RM79-22 and should be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Philip Yates, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 275-0427

Introduction

This interpretive rule addresses the extent to which existing contracts for the sale of natural gas may be amended to provide for the payment of some or all of the prices established under the NGPA. The Commission has considered this question in Docket No. RM79-22, the proceeding which resulted in Order No. 23, relating to the effect of the NGPA on price escalator clauses. In a proposed rule issued February 13, 1979, we took the same substantive position on contract modifications as we now adopt. The comments on the proposed rule which were relevant to this subject did not, as a general matter disagree with that position. Rather, the comments were directed at the related question of pipeline pass-through discussed below.

General Rule

Section 101(b)(5) of the NGPA provides that if any natural gas qualifies under more than one maximum lawful price, the highest price for which the gas is eligible becomes the applicable maximum lawful price. The Commission believes contractual amendments consistent with this section are permitted in both interstate and intrastate contracts. The most common, though not the only example of situations arising under the NGPA which illustrates this principle is when natual gas from a well subject to an existing contract is subsequently determined to be eligible for a higher price under sections 102, 103, 107 or 108 of the Act. If this occurs, the NGPA does not preclude parties from negotiating for and executing amendments providing for the payment of the higher price. This is true without regard to whether the contract was an "interstate" or "intrastate" contract.

Although the rule stated above applies in all cases, special attention should be given to contracts governed by section 105(b)(1) of the NGPA. That section applies to intrastate contracts under which the contract price on November 9, 1978, did not exceed the new gas price established in section 102 of the Act. For these contracts the maximum lawful price is the price under the terms of the contract as such contract was in effect on November 9, 1978.

With respect to these contracts, amendments may only be executed to provide for payment of any higher maximum lawful price for which natural gas sold under the contract is determined to be eligible. For example, assume that on November 9, 1978, natural gas was sold under an existing intrastate contract for $1.50/MMBtu, (or any price less than $2.06, the new natrural gas price in November). Since under section 105(b)(1), the price under the terms of the contract, ($1.50 per MMBtu) is the maximum lawful price, no contractual amendment could provide for a higher price. But if subsequent to enactment a well covered by the contract was determined to be a stripper well, under section 101(b)(5) the gas from that well would be eligible under both sections 105(b)(1) and 108. In that case the applicable miximum lawful price would be the stripper well price. Accordingly, an amendment providing for the payment of that higher price would be permitted. The same result would occur any time gas sold under the contract was determined to be eligible for any price higher than $1.50 per MMBtu (e.g., 102 new natural gas or 103 new onshore production well gas).

The operation of the rule on contracts governed by section 105(b)(2) of the Act is also worth noting. In these cases, the contract price exceeded the section 102 price on November 9, 1978, and the applicable maximum lawful price exceeded $2.06. Under section 105(b)(2), the ceiling price is the contract price plus the monthly inflation adjustment. Accordingly, if the contract did not already permit it, amendments to contracts subject to the maximum lawful price in 105(b)(2) could be executed to provide for the payment of the inflation adjustment. Also, amendments could be executed to provide for payment of the stripper well price established in section 1208 of the NGPA, if wells covered by the contract were determined to be eligible for that price.

Other general examples may be helpful. If contractual authorization does not exist in an interstate contract to collect the inflation adjustment provided in section 104 of the Act, the NGPA does not preclude an amendment providing for its payment. Similarly, the NGPA does not preclude amendments to interstate contracts to provide for the payment of prices under sections 102, 103, 107 and 108 if natural gas under the contract qualifies for those prices.

Two associated points should be noted. First, since collection of the higher price may be contractually authorized, amendments providing for the interim collection of such prices, pursuant to Part 273 of the regulations, are similarly permissible. Second, for the same reasons, all contracts may be amended to provide for a clause authorizing the payment of the highest NGPA price for which any natural gas sold under the contract may become eligible, i.e., both interstate and intrastate contracts may be amended to include escalator clauses which reference the highest applicable NGPA prices.

Pass-through of NGPA Prices

In the preamble to the February 13, 1979, proposal, we indicated that pass-through of increased gas purchase costs resulting from contract modifications providing for a price not in excess of the maximum lawful price is permissible in the absence of fraud, abuse, or similar grounds. We also indicated that pass-through would not be precluded if modifications were negotiated in an arms length transaction.

A number of participants in Docket No. RM79-22 suggested that the Commission affirmatively state that contract modifications must be supported by additional consideration. Other comments suggested that the Commission define arms-length bargaining. Upon consideration of these comments, we have determined that it is neither useful nor necessary to impose the requirement or define that term. We note particularly the difficulties of defining arms-length bargaining because of the wide diversion of views expressed on this part. Accordingly, we are convinced that we should abandon our previous reference to that test.

Section 601(c)(2) of the NGPA provides that the Commission may not deny an interstate pipeline the recovery of maximum lawful prices paid by the pipeline unless ". . . the Commission determines that the amount paid was excessive due to fraud, abuse, or similar grounds." The Joint Statement (pg. 124) indicates that "[t]he conferees do not intend to guarantee passthrough of costs of natural gas purchases in cases of fraud or abuse as *determined by the Commission.*" [emphasis supplied] A number of comments requested that we define the term "fraud, abuse or similar grounds."

The statute and the statement quoted would permit the Commission to make the determination on a case-by-case basis, or to prescribe general rules defining in part or fully the phrase "fraud, abuse or similar grounds." We are aware that general guidance as to the circumstances that would constitute grounds for a determination of fraud abuse or similar grounds would be desirable. However, we believe that if such guidance or general rules can be developed, they must emerge from a number of individual cases in which the Commission considers this issue. Until sufficient experience under the law is acquired we believe that general statements concerning the application of the standard cannot be formulated with sufficient precision to assist those pipelines concerned with its application.

The Commission will revise section 270.205 of its regulations by adding a paragraph entitled "Modification of existing contracts." This paragraph will summarize the foregoing discussion.

(Natural Gas Act, as amended, 15 U.S.C. 717 *et. seq.*, Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, Department of Energy Organization Act, Pub. L. 95-91, E. O. 12009, 42 FR 46267)

In consideration of the foregoing Part 270 of Subchapter H, Chapter I, Title 18, Code of Federal Regulations, is amended as set forth below. Because this is an interpretive rule, deferral of the effective date of the rule is not required. Accordingly, the rule will be effective immediately.

By the Commission. Commissioner Sheldon voted present.

Kenneth F. Plumb,
Secretary.

[¶ 30,059]

44 F. R. 34473 (June 15, 1979)

18 CFR Part 271

[Docket No. RM79-3]

Ceiling Prices; High-Cost Natural Gas

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission promulgates final regulations implementing section 107(a) of the Natural Gas Policy Act of 1978, which deals with the maximum lawful price for deep, high-cost natural gas.

DATES: June 13, 1979.

ADDRESSES: All findings should reference Docket No. RM79-3 and should be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Philip Yates, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, 202-275-4212.

SUPPLEMENTARY INFORMATION: On December 1, 1978, the Federal Energy Regulatory Commission issued Interim Regulations in Docket No. RM79-3 implementing the Natural Gas Policy Act of 1978 (NGPA). (43 FR 56448). Subpart G of Part 271 set forth regulations implementing section 107(a) of the NGPA, to provide incentive prices for deep, high-cost natural gas.

Section 107(b)(2)-(4) also authorized the Commission to establish incentive prices for gas from geopressured brine, occluded natural gas produced from coal seams, gas from Devonian shale, as well as gas produced from other conditions which have been determined by the Commission to present extraordinary risks or costs. However, due to statutory deadlines imposed by the NGPA, the Commission did not promulgate regulations to implement section 107(b).

During the 60-day comment period on the interim regulations, ten comments were received addressing the issuance of section 107(b) regulations. Some made general requests for expeditious promulgation, others suggested specific definitions for the particular categories listed in section 107(c).

The comments in favor of rapid implementation of section 107(b) took the position that incentive prices are required to maximize natural gas production. However, one comment indicated that the maximum lawful prices allowable under other provisions of the NGPA may provide sufficient incentives to produce adequate natural gas supplies. Further, the comment suggested that it may be exceedingly difficult to determine what is "necessary" incentive pricing, and what is a windfall to a producer.

Concurrently with this final rulemaking, the Commission is issuing a notice of inquiry, requesting comments to assist it in a policy examination of rules implementing section 107(b) and (c) of the Natural Gas Policy Act of 1978. Additionally, we are requesting comments on a notice of proposed rulemaking issued today, in which we set forth proposed definitions for those categories specifically listed in section 107. The issues raised by the comments on the proposed definitions will be considered together with the responses to the notice of inquiry.

Eleven other comments were received on Subpart 271 G. Three made reference to the Commission's statement in the order of December 1, 1978, in Appalachian Exploration and Development, Inc., *et al.*, Docket No. CI76-590, *et al.*, that it intended to issue, in the near future, a "transitional rule governing the processing of all optional procedure cases [18 C.F.R. § 275] filed before December 1, 1978." On February 7, 1979, the Commission issued an Order Granting Rehearing For Purposes of Further Consideration in Docket No. CI76-590. We expect to consider a transitional rule in the near future.

Several comments requested that measurement of well depth in § 271.704

be made from the top of the "Kelly bushing"[1] rather than "surface of the ground." One rationale for this proposed change is that well logs refer to this point. More importantly for offshore wells the reference to the Kelly bushing will include the depth of the water in the measurement of the 15,000 foot depth.

Section 107 does not establish a cost-based maximum lawful price for deep wells. However, the costs involved in producing gas from deep wells is a factor which the Commission may consider in implementing the section. Recognizing the costs of constructing offshore drilling platforms, we believe that it is reasonable to conclude that it is consistent with the statute to include in the measurements of well depth, the depth of the water in which a producer must drill. In order to effectuate this conclusion, the Commission by this order amends § 270.102(6), which defines "surface location." Pursuant to this order, "surface location" will remain the same for onshore wells; i.e., the earth's surface. However, for wells drilled in permanent surface waters, the "earth's surface" means "the mean elevation of the surface of the water." In conformance with this amendment, § 271.704 is amended to require measurement of depth for section 107(a) purposes to be "from the surface location to the highest perforation point in the completion location."

Two other comments addressed the use of "true *vertical* depth" in § 271.704. It is asserted that all wells tend to corkscrew as they are drilled. Also, offshore wells are drilled directionally, to allow more undersea acreage to be tapped from one drilling platform. Since the cost of a well is determined by the length of the bore, and not the vertical depth of the highest penetration, these comments recommend replacing "true vertical depth" with a reference to actual well bore length.

There is validity to these statements regarding costs. However, Congress has explicitly adopted the standard of "true vertical depth" in section 101(b)(1) of the NGPA. Thus, the Commission is precluded from adopting a different standard in § 271.704.

The Joint Explanatory Statement of the Committee on Conference, at page 88, anticipated that "some new wells will produce from depths close to 15,000 feet, and some reentries will produce from depths below 15,000 feet, both possibly involving costs greater than normal . . ." The Statement went on to acknowledge that "[t]he Commission may determine that such wells should receive special price treatment under this section. . . ."

It appears that the wells described in the comments, like the wells described in the Statement, may qualify under section 107(c)(5), as natural gas "produced under such other conditions as the Commission determines to present extraordinary risks or costs." Accordingly, these comments will be considered in the notice of inquiry concerning section 107(c)(5), issued today. The Commission invites additional comments addressing this issue.

One other comment addressed § 271.704 of the interim regulations, requesting that the Commission's definition of deep, high-cost natural gas include wells begun before February 19, 1977, if redrilling the well entails substantial expense. Alternatively, the comment suggested such redrilled deep wells be classified as high-cost gas under section 107(c)(5). The Commission will not amend § 271.704 in the manner suggested; it is contrary to the plain language of section 107(a) and (c)(1), and inconsistent with the intent of the section as evidenced by the above quoted passage from The Joint Explanatory Statement of the Committee on Conference. The comment's alternative suggestion will be examined with comments elicited by the notice of inquiry addressing section 107(c)(5).

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[1] The "Kelly bushing" is that part of the drilling rig which transfers the power from the rotary table to the pipe in the ground. For onshore wells, it may be as high as 20 feet from the surface of the ground.

The regulations in Subpart G of Part 271 were originally proposed for comment in November of 1978 and issued as interim regulations on December 1, 1978 (43 FR 56448 (Dec. 1, 1978)). For 60 days thereafter comments were received and during that period public hearings were held on these regulations. By this process the Commission complied with the provisions of section 502(b) of the NGPA which requires that "[t]o the maximum extent practicable," an opportunity for the oral presentation of data, views, and arguments be afforded for certain regulations under the NGPA.

The amendments to Subpart G of Part 271 contained in this order rest upon considerations given to the information received during the above described, comment, and hearing process. Accordingly, the Commission finds that further notice and public procedure on these rules are unnecessary and impractical and that good cause exists to dispense with additional notice and procedure. Subpart G of Part 271, as amended, will be effective in 30 days as final regulations.

(Natural Gas Act, as amended, 15 U.S.C. 717, et seq.; Energy Supply and Environmental Coordination Act, 15 U.S.C. 791, *et seq.;* Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350; Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267)

In consideration of the foregoing, Subpart G of Part 271 of Subpart H, Chapter I, Title 18, Code of Federal Regulations, issued as interim regulations (43 FR 56448 (December 1, 1978)), are promulgated as final regulations and amended as set forth below, effective 30 days from the issuance of this order.

By the Commission.
Kenneth F. Plumb,
Secretary.

[¶ 30,060]

44 F. R. 34475 (June 15, 1979)

18 CFR Part 275

[Docket No. RM79-3]

Commission Determinations and Review of Jurisdictional Agency Determinations

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rules.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is issuing final regulations implementing section 503 (b) and (d) of the Natural Gas Policy Act of 1978 (NGPA) which deals with Commission review of jurisdictional agency determinations of the NGPA pricing category for natural gas.

EFFECTIVE DATE: July 16, 1979.

ADDRESSES: All filings should reference Docket No. RM79-3 and should be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Philip Yates, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 275-4212.

I. Background

On December 1, 1978, the Federal Energy Regulatory Commission (Commission) issued interim regulations implementing the Natural Gas Policy Act of 1978 (NGPA) (43 F.R. 56448). In the 60-day comment period on the interim regulations, 28 comments were received on Part 275; some of the suggestions made by the comments have been incorporated into the final rule.

II. Discussion of Comments

Part 275 generally describes the procedures by which the Commission will review jurisdictional agency determinations. It reflects section 503 of the NGPA in setting forth the grounds on which determinations may be reversed or remanded. It also provides a 15-day protest procedure under which persons may object to determinations and submit documentary evidence relative to the determination. Finally, it establishes procedures for reopening and possibly vacating determinations on the basis of material facts which were either untrue or omitted from the record before the jurisdictional agency. Section 275.201 of the interim regulations provides that the Commission will publish a notice in the **Federal Register** of the receipt of a jurisdictional agency's determination, and specifies the contents of that notice. One comment requested that the notice contain the following additional information:

1. The rate schedule number, so that interested parties can inspect the producer's contract,
2. A summary by the state agency of information in its files inconsistent with its determination, and
3. The price sought and the statutory regulatory authority sought to be invoked.

The comment indicated that the rate schedule number is necessary so that interested parties may inspect contracts in the Commission's files to ascertain, "among other things, the nature of the contractual authority for the price sought." The inclusion of the rate schedule number will not be included at this time. However, the Commission is actively engaged in preparing an order establishing the proper procedure for examining questions of contractual authority. This issue will be more fully discussed in that order.

The comment's second request, for the publication of a summary by the jurisdictional agency of information inconsistent with its determination, is more properly addressed in connection with § 274.104, which contains the requirements of the jurisdictional agency's notice to the Commission. Section 274.104 does not presently require such a summary. The comment will be considered with other comments on that section.

However, if such a summary is required to be sent to the Commission, we do not believe that it should be included in the notice published in the **Federal Register**. The published notice is designed to bring to the attention of interested persons, through a synopsis of the basic facts, that a particular well has been determined to qualify for a certain NGPA pricing category. The notice itself, by definition, does not provide the public with enough information to permit a complete analysis. That information is available in the public files for inspection. For the Commission to provide in the notice the amount of information suggested for the thousands of jurisdictional agency determinations would be administratively infeasible and would place an impossible burden upon the Commission and the **Federal Register**.

The third request, for the price charged, is also unnecessary. The section of NGPA under which the determination is made is included in the notice. Reference to that NGPA section will show what price can be charged, assuming contractual authority exists to collect that price.

Section 275.201(d) of the interim regulations provides that the notice in the **Federal Register** shall provide that protests may be filed within 15 days of the Commission's public notice. Some comments recommended that this time limit be reduced from 15 days to 10 days, with an additional 10-day period provided for the filing of responses to protests.

The time period for protests was originally set by attempting to balance the need for adequate time for interested persons to review the determination and make filings, against the statutory requirement that the Commission act on determiniations within 45 days. Since no protests have yet been received, and the comments are not based on arguments that the time limits are unreasonable, there is no reason to change this requirement. As more experience is gained under this section, we may determine that some adjustment in the time and procedures for protests may be necessary. At present, the 15-day period will not be changed; however, to make the regulations clearer, the 15-day limit has been made explicit in § 275.203(a).

One comment suggested that Part 275 be amended to provide that notice of a preliminary finding or a reopening of a determination be sent by all those persons who are purchasing gas at the wellhead to all those to whom the purchaser tenders payment for the gas. The concern underlying this request is valid. A subsequent purchaser of a well may not receive notice of a preliminary finding or reopening because the Commission will not be aware that the person who filed for the pricing determination is no longer the owner of the well.[1] However, without reaching the question of the Commission's legal authority to require such notice, we conclude that this is a matter to be resolved between the buyer and seller of a natural gas well. Thus, the Commission declines to require wellhead purchasers of natural gas to supply the notice requested by the comment.

Two comments suggested that the Commission include additional grounds for issuing a preliminary finding. One suggested that the Commission issue a preliminary finding if the Commission believes the jurisdictional agency determination may be unreasonable. Another suggested that a preliminary finding issue on the grounds of absence of contractual authority for the determination.

A preliminary finding is a required step under our regulations, before the Commission can issue an order reversing or remanding a jurisdictional agency determination. The statutory grounds for a reversal or remand are clear: (1) a reversal is required if the Commission finds that a determination is not supported by substantial evidence in the record upon which the determination was made. (Section 503(b)(1)(A)); and (2) a remand may occur if the Commission finds that its files contain information inconsistent with a determination. (Section 503(b)(1)(B)). A preliminary finding will not issue unless the Commission concludes that one of the statutory grounds for reversal or remand may exist. Neither of the comments' suggested grounds are included in the statutory grounds for remand or reversal. Thus, a preliminary finding cannot be issued solely because the Commission feels that a jurisdictional agency determination is unreasonable or that contractual authorization is lacking to collect the highest price allowable under an NGPA pricing category.

Several comments addressed the 45-day period in which the finding under § 275.202(b) may be made that the notice of the determination sent by the jurisdictional agency to the Commission is incomplete. One suggested that the 45-day period begin on the date the notice of determination is published in the Federal Register. Some indicated that such a finding could be made in a shorter time, others felt that the period was unnecessary, given the certification which must be filed under § 274.104(a)(5), stating that all required information has been supplied. Still others expressed the opinion that tolling the 45-day statutory time period by issuing an incomplete notice is an unwarranted intrusion by the Commission into state jurisdiction and that this provision is subject to administrative abuse.

The full 45-day period will be retained, beginning upon the receipt of the determination by the Commission. The full period is required because it is estimated that 40 to 50 thousand jurisdictional agency determinations will be filed in the first year of the NGPA. The beginning date for the 45-day period is statutorily required under section 503(b)(1)(F). The tolling provision is required because the certification required by § 274.104(a)(5) may not be accurate; the Commission must have time to reach its own conclusion as to the adequacy of the information filed by the jurisdictional agency. Finally, all the information required to be filed may be necessary for the Commission to make a "substantial evidence" determination, as required by section 503(b)(1)(A). If the information is not supplied, the jurisdictional agency's determination may not be supported by substantial evidence;[2] unless a tolling provision is provided, filings by jurisdictional agencies which lack material information would require reversal.

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[1] Section 503(b)(3) requires that the notice be sent to "those parties identified in the notice [sent] to the Commission of [the pricing] determination.

It is anticipated that once state agencies become familiar with the determination process, this section will be little used. However, at present, our experience has shown it to be necessary. It would be foolish to expect state agencies, in making their first determinations, to do so completely without error. In fact, it is remarkable how well most are performing.

One comment suggested that informal conferences after preliminary findings be eliminated because of the possibility of *ex parte* communication; instead, the commentor would allow only written filings. This suggestion is rejected; *ex parte* problems will be no more substantial in this context than in any other informal conference with staff.

Several comments address § 275.202(e), indicating confusion with respect to the procedures to be followed if the Commission makes a preliminary finding on its own motion. These comments are well taken. Section 275.202(e) is amended to make clear that the procedures which the Commission will follow after a preliminary finding are the same without regard to whether or not a protest has been filed. The only difference is that the Commission will issue a final order in any case in which both a protest was filed and a preliminary finding was made, whereas if the preliminary finding is made by the Commission on its own motion, the issuance of a final order is not required. If none is issued, § 275.202(e)(3) states that the jurisdictional agency determination will become final 120 days after the date of the preliminary finding.

A number of comments suggested that protests should be made under oath and that protestors should be limited to those persons who participated in the state agency proceeding, absent a showing of good cause for failure to participate. The Commission addressed both of these issues in the preamble to the interim regulations. We indicated that if the protest procedure was being abused, the oath requirement could be imposed. We also indicated that the Commission could not prescribe procedures applicable to jurisdictional agency determinations, and that the limited time within which the Commission must act would not allow for resolution of controversies over good cause for failure to appear before the jurisdictional agency. Again, until experience dictates the need for these types of changes, the position previously articulated in the preamble will be maintained.

Two comments suggested that a preliminary finding not issue if a protest raises only harmless error. We believe that section 503(b)(2) now provides this discretion. Thus, there is no need for the regulation to be amended, because § 275.202(a)(1)(ii) tracks the language of the statute.

One jurisdictional agency suggested that it is inconsistent with the NGPA to permit protestors to submit information with their protest, and have that information become part of the "public records of the Commission," within the meaning of section 503(b)(1)(B). The Commission believes that it is not only consistent with the statute but is required by the framework of the NGPA. Section 501(a) requires the Commission to "issue . . . such rules and orders as it may find necessary or appropriate to carry out its functions under this Act." One of those functions is the review of jurisdictional agency determinations. It would be unreasonable for the Commission not to consider reliable evidence submitted by a protestor, within the 45-day statutory period, in reviewing a determination. Consequently, § 275.203(b)(3) will be retained.

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[2] Although our practice has not been to declare a filing incomplete for a minor technical deficiency, the final rule in § 275.202(b)(1) has been amended to make clear that an incomplete notice will not be issued unless the deficiency is material.

Two comments would have the Commission remand all determinations that are required to be reopened, rather than have the Commission take initial jurisdiction of the matter. It is indicated that section 503 of the NGPA contemplates that initial jurisdiction for pricing determinations lies with the jurisdictional agency.

Section 503(d) states that jurisdictional agency determinations, if no longer subject to review by the Commission or the courts, "shall thereafter be binding." However, the determination is *not* binding if it was based on (1) any untrue statement of material fact or (2) a misleading omission of material fact. The section does not indicate the procedure which should be utilized to ascertain whether the determination was based on such misinformation. Pursuant to the authority granted in section 501(a), the Commission has set out in § 275.205 what it considers to be the appropriate procedure for "reopening" jurisdictional agency determinations. Section 275.205(d) has been amended slightly to clarify the effect of an order vacating a jurisdictional agency determination.

The procedure set out entails four distinct steps: (1) an initial finding by the Commission, on its own motion or in response to a petition, that a material misstatement or omission may have occurred; (2) an opportunity for a presentation of views on that issue; (3) a determination by the Commission, based on the information supplied by all interested parties, whether the misstatement or omission occurred, and if so whether the determination should be vacated because the misstatement or omission was relied upon by the jurisdictional agency, and (4) if the determination is vacated, the Commission must then decide how much of the producer collections were in excess of the otherwise applicable maximum lawful price, and if appropriate, order that amount refunded.

In the process described above, the Commission will not make determinations which section 503(a)(1) assigns to jurisdictional agencies; we will merely vacate a determination based on a material misstatement or omission. The procedure will be free at that point to apply to the jurisdictional agency for a determination. Consequently, the flexibility of § 275.205(d) will be retained.

One comment would have the Commission preclude reopening a pricing determination if the material misinformation was supplied in good faith, to provide producers with truly final determinations. This suggestion is contrary to the statutory provisions of section 503(d), which make no reference to good faith, and is rejected.

The 10-day period in the last sentence of § 275.206(b) has been reduced to 5 days, because 10 days is the maximum time that is allowed for the processing of requests under the Freedom of Information Act, 5 U.S.C. § 522. The Commission requires some time to make the initial determination that the information will be released before notice of the release is given.

Finally, § 275.201(b) has been amended to delete the reference to "Part I" of FERC Form No. 121, since that form does not have a "Part I."

III. Public Procedures and Effective Date

The regulations in Part 275 were originally proposed for comment in November 1978 and issued as interim regulations on December 1, 1978 (43 FR 56448 (Dec. 1, 1978)). For 60 days thereafter comments were received and during that period public hearings were held on these regulations. By this process the Commission complied with the provisions of section 502(b) of the NGPA which requires that "[t]o the maximum extent practicable," an opportunity for the oral presentation of data, views, and arguments be afforded for certain regulations under the NGPA. The amendments to Part 275 contained in this order rest upon considerations given to the information received during the above described notice, comment, and hearing process. Accordingly, the Commission finds that further notice and public procedure on these rules is unnecessary and impractical and that good cause exists to dispense with additional notice and procedure, and to make Part 275, as amended, effective in 30 days as final regulations.

(Natural Gas Act, as amended, 15 U.S.C. 717, *et seq.;* Energy Supply and Environmental Coordination Act, 15 U.S.C. 791, *et seq.;* Natural Gas Policy Act of 1978, P.L. 95-621, 92 Stat. 3350; Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267)

In consideration of the foregoing, Part 275 of Subchapter H, Chapter I, Title 18, Code of Federal Regulations, issued as interim regulations (43 FR 56448 (Dec. 1, 1978)), are promulgated as final regulations and amended as set forth below, effective 30 days from the date of issuance of this final order.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,061]

44 F. R. 34936 (June 18, 1979)

18 CFR Parts 1, 2

[Docket No. RM78-16]

Procedure for Submission of Settlement Agreements

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Commission is promulgating a rule which contains procedures for the submission of settlement agreements and Commission treatment of contested and uncontested offers of settlement. The rule defines for the first time the information to be included in offers of settlement and prescribes settlement procedures that enable the Commission to expedite consideration of settlements filed directly with the Commission or certified by the presiding officers. By streamlining settlement procedures, it is expected that parties to proceedings before the Commission will find the settlement process a more attractive alternative to litigation.

EFFECTIVE DATE: June 15, 1979.

FOR FURTHER INFORMATION CONTACT: Kenneth E. Richardson, Federal Energy Regulatory Commission, Office of Opinions and Review, 825 North Capitol Street, N.E., Room 9216-C, Washington, D.C. 20426, (202) 275-4200.

Background

On July 24, 1978, the Commission issued a Notice of Proposed Rulemaking on Settlement Agreements, in which the Commission advanced for public comment revised procedures for the submission of offers of settlements.[1] Twenty-eight responses[2] to the Commission's request for written comments were received. The majority of those commenting supported the Commission's proposed rulemaking, and several commentors offered helpful suggestions for clarifying the proposed procedures.

The purpose of the proposed rule is to define in the regulations for the first time information which shall be included in offers of settlement and to prescribe settlement procedures that enable the Commission to expedite consideration of settlements filed directly with the Commission or certified by Presiding Officers, particularly uncontested settlements. By improving our settlement procedures and reducing the length of time presently required for processing settlements of all types, it is our hope that participants in proceedings before the Commission will increasingly seek the benefits of the settlement process to avoid the alternative of costly and often times lengthy litigation before the Commission. The direct costs of regulation are borne most often by the ultimate consumer but indirect or nonquantifiable costs arising from litigation due to uncertainty and delayed managerial decisions or opportunities foregone may be suffered by shareholders as well.

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[1] July 28, 1978, 43 FR 32814.

[2] Requests to file comments after the August 31, 1978, deadline are hereby granted.

The Commission wishes to emphasize the importance of voluntary settlements to the orderly and expeditious conduct of its business. During the period when responsibility for administering the Natural Gas Act and the Federal Power Act was in the hands of the Federal Power Commission, that agency had a strong policy favoring the disposition of cases through settlements. The FPC and the courts recognized that the Commission could not possibly cope with the flood of business engendered by its jurisdictional statutes if the outcome of a substantial proportion of that business were not the result of voluntary settlements entered into by the parties. *See, Mitchell Energy Corp.* v. *FPC*, 519 F. 2d 36, 40 (5th Cir. 1975); *Texas Eastern Transmission Corp.* v. *FPC*, 306 F. 2d 345, 347 (5th Cir. 1962). We adhere to that view.

Enactment of the Natural Gas Policy Act of 1978, 92 Stat. 3351 (1978), and other portions of the National Energy Act will increase substantially the volume of adjudicative business which this Commission, as successor to the Federal Power Commission, must handle under both the old and the new energy legislation. These developments would seem to make it even more important for those charged with carrying on the Commission's business to do so with a view towards promoting settlements whenever they are in the public interest.

The Commission's Administrative Law Judges have a special responsibility in this respect. Both the Commission's rules of practice and procedure (18 CFR 1.18) and the Administrative Procedure Act (5 U.S.C. 556(c)(6)) authorize Administrative Law Judges to call the parties to a dispute together for the purpose of settlement of the issues.

The Commission is particularly desirous of having its Judges attempt to secure settlements in all cases where settlement is possible and would be in the public interest. The Administrative Law Judges are encouraged to use all of the tools and resources at their command to that end.

Summary of the Rule

The new rule expands upon the present rules regarding settlements by requiring all offers of settlement to be filed with the Secretary and by providing a means of expeditious Commission consideration of contested and uncontested offers of settlement. While clarifying the procedure applicable to offers of settlements, the amended § 1.18(e) does not alter § 1.18(a) of the present rule which gives wide latitude to participates in any proceeding to hold conferences to provide the opportunity for the submission and consideration of offers of settlement. Any party to a proceeding may submit at any time an offer of settlement to all parties, or request a conference for consideration of a settlement offer. the rule does, however, eliminate the current clause in paragraph (e) permitting Submission at any time of offers of settlement to the commission (or to staff counsel for transmittal to the Commission). The new § 1.18(e) also sets forth the information which at a minimum must be submitted by persons filing offers of settlement. An offer of settlement must now include a proposed Commission order accepting the settlement. The new rule also retains the privilege afforded offers of settlement and proposed stipulations not agreed to.

The new portions of § 1.18(e) provide that once a hearing has been ordered until the time the Presiding Officer certifies the record to the Commission, an offer of settlement must be filed with the Secretary of the Commission for transmittal to the Presiding Officer assigned the case, or, if a Presiding Officer has not yet been assigned, to the Office Director responsible for the assignment.[3] Offers of settlement will be filed with the Secretary for transmission to the Commission if a hearing has not been ordered or the case has been certified by the Presiding Officer.

In order to expedite the process after an offer of settlement is filed, the present provisions (§ 2.1) that an offer of settlement be noticed for comment in the **Federal Register** are replaced by new service provisions. Section 1.17(b) of the regulations requires that papers filed with the Commission be served upon persons designated on the official service list. However, in order to strike a balance between the need for expedition and the desirability of giving notice to those persons most likely affected by such an offer, new § 1.18(e)(1)(vi) provides that all offers of settlement filed with the Secretary of the Commission shall be served on all persons who were required by the Commission's rules to be served with the applications or pleadings initiating the proceeding. All persons served shall also be informed at the time of service the date on which comments are due on the offer of settlement. This procedure provides a greater opportunity for those persons who are not parties to the proceeding but who are most likely to be interested in a settlement to be apprised of its terms. They will now receive actual notice rather than constructive **Federal Register** notice of settlement offers.

The due date for comments will no longer be delayed until after notice of the settlement offer is published in the **Federal Register**. Regardless of whether the settlement is filed for transmittal to the Commission or for transmittal to the Presiding Officer, comments on an offer of settlement must be filed with the Presiding Officer or the Commission, as appropriate, on or before 20 days of the filing of the offer of settlement. Replies are to be filed on or before 30 days after filing of the settlement offer. However, the Presiding Officer or the Commission may provide for a different deadline for comments or reply comments. Failure to file comments will be deemed a waiver of the right to file comments on the offer of settlement (§ 1.18(e)(2)). This time period for comments is shorter than the time which has been permitted previously.

The revision of the notice procedure is intended to reduce the time now consumed in obtaining comments necessary to determine whether a settlement is contested and to enable earlier review of a settlement for decision. If the comments indicate that a settlement offer is uncontested, or that at least a portion of it is uncontested and severable from the contested part of the settlement, the new rule permits quicker decisionmaking. If the settlement is transmitted to the Presiding Officer, the Officer is to certify the settlement and the filings and submittals and the formal record (if one is compiled) together with a statement that the settlement is uncontested (§ 1.18(e)(3)). the Commission will expedite consideration of uncontested settlements filed with the Secretary of the Commission for transmittal to the Commission or certified by a Presiding Officer.

Under the Commission's present rules, a Presiding Officer may certify a settlement even if the comments indicate that the settlement is contested. However, if the settlement is contested by a party to the proceeding, then the rule permits a Presiding Officer to certify a contested settlement or a contested portion of a settlement only in accordance with certain conditions imposed in order to assure that a sufficiently developed record exists on which a reasoned decision can be based. The Presiding Officer may certify such offer of settlement to the Commission only if the parties concur on a waiver of the initial decision or if no contested issue of material fact exists, if the Presiding Officer determines that the record contains substantial evidence to enable the Commission to reach a decision on the merits of contested issues, and if the parties have had an opportunity to exercise such rights as they may have with respect to the opportunity to present evidence and cross-examine opposing witnesses (§ 1.18(e)(4)(ii)). If these conditions are not present, the Presiding Officer may direct such further procedures as he deems appropriate, including certification of the settlement at a later time if the conditions are then met.

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[3] An Office Director is chosen rather than the Chief Administrative Law Judge because in certain cases the Commission may refer a matter to a Presiding Officer who is not an Administrative Law Judge and who is designated by the General Counsel or, for appeals for rulings of the Office of Hearings and Appeals, Department of Energy, by the Director of the Office of Opinions and Review.

If the Commission staff is the only contesting participant, the Presiding Officer may exercise his discretion to certify the offer of settlement even if the above conditions are not met. In this regard, the Commission wishes to emphasize the importance it places on the role of the Commission staff in representing the public interest in proceedings before the Commission. The staff performs an important public function in developing the records and testing the case presented by the other parties. Where the staff has not had an opportunity to present evidence and to cross-examine the witnesses of other parties, the Commission expects that the Presiding Officer will consider very carefully the basis for certifying an offer of settlement opposed by the staff. In accordance with present procedure, this decision is left to the sound discretion of the Presiding Officer. However, the Commission would expect that in the exercise of this discretion the Presiding Officer will give careful consideration to the need to develop the record as well as the importance of expediting decision-making.

Settlements which are contested in whole or in part and which are filed with the Secretary for transmittal to the Commission may be considered and approved or disapproved if the record contains substantial evidence upon which to base a reasoned decision. If substantial evidence is lacking or the contested portion of the settlement cannot be severed from the remainder of the settlement for decision, the Commission may order proceedings before a Presiding Officer for receiving substantial evidence upon which a decision can reasonably be based or other appropriate procedures. (§ 1.18(e)(4)(i))

Section-by-Section Analysis and Comment Analysis

Section 1.18(e)(1)

This subparagraph is revised to provide new procedures for the filing offers of settlement with the Secretary of the Commission.

The new § 1.18(e) applies to offers of settlement filed on or after June 15, 1979 in any Commission proceeding other than a rulemaking of general applicability or an investigation under Part 1b of the Regulations. An offer of settlement includes any proposal to modify an offer of settlement.

Any participant to a proceeding may submit at any time an offer of settlement to the Secretary of the Commission or request a conference for purposes of discussing settlement. The Secretary will transmit the offer to the Presiding Officer, Office Director, or the Commissioners, as appropriate. A settlement offer must contain the offer itself, an explanatory statement, and references to documentary support for the offer. An offer of settlement shall also include a proposed Commission order accepting the settlement and disavowing any precedential value for the decision. The settlement offer must be served on all participants and on all persons required to be served with the applications or pleadings initiating the proceeding.

Any offer of settlement which is not approved by the Commission is privileged.

Florida Power & Light Company suggests that the Commission allow the party submitting an offer of settlement to include "any explanatory data it deems appropriate" in the offer of settlement. The definition of "offer of settlement" has been modified to include an "explanatory statement."

To avoid the confusion which Florida Power & Light foresees over what must be included in formal offers of settlement as opposed to preliminary offers of settlement prepared only for purposes of negotiation and conferences, the new rule provides for consideration by the Commission only of offers of settlement filed with the Secretary.

Exxon Corporation, Consolidated Edison Corporation, and Southern California Edison Corporation each noted that this section should provide more clearly that, before a hearing has been ordered, offers of settlement should be filed directly with the Commission and subparagraph (1)(ii) has been modified accordingly.

Exxon, Southern California Edison, and Tenneco also request that adjustments to offers of settlement, offers of settlement not agreed to, and accepted settlements be privileged, in the same manner that unaccepted offers of settlement are privileged. The Commission agrees, insofar as the comments refer to offers not approved by the Commission, and has changed the clause (v) to reflect this recommendation. The privilege cannot be accorded to offers approved by the Commission.

Pennzoil Company, Tenneco Oil Company and Florida Power & Light Company request the Commission to change the word "participant" to "party". The term participant has been used as defined in § 1.1(f)(2) of the regulations, to include the Commission's staff, and to indicate a limited participation in proceedings by persons other than parties. The word "party" does not include staff.

The Public Service Commission of New York (PSNY), Tenneco, United Gas Company, and the Interstate Natural Gas Association of America (INGAA) [4] request that the Commission delete the sentence requiring the participants submitting the offer of settlement to "state whether the settlement is a package, with no severable parts, or whether any specific issues may be separated from the settlement for separate decision, should the need for a separate decision arise." The commentors believe that this requirement would hamper settlement negotiations, and could create contested issues which might otherwise more easily be settled. The Commission agrees that this could hinder settlement negotiations and accordingly accepts the recommendation to delete this sentence from the rule. However, we encourage those persons filing offers of settlement to decide and determine during negotiations if parts of settlements are severable and advise the Presiding Officer or Commission in order to permit a prompt decision on the uncontested parts of a settlement.

Section 1.18(e)(2)

This subparagraph provides for a date certain for the filing of comments and reply comments. It has been clarified to provide for the filing of comments on the offer of settlement with the Presiding Officer, if the offer of settlement has been filed for transmittal to the Presiding Officer, or with the Commission if the offer of settlement has been filed for transmittal to the Commission.

Exxon Corporation recommends that, rather than publishing a notice with the Federal Register, the Commission should allow each participant to comment on the offer of settlement within 10 days of its submission to the Presiding Officer or the Commission. The thrust of this recommendation is adopted. Notice in the **Federal Register** will no longer be required. Participants must submit comments to the Presiding Officer or to the Commission, as appropriate, within 20 days of the filing of the offer of settlement. An additional 10 days is allowed for filing reply comments. A participant's failure to file comments within that period of time will be deemed a waiver of its right to file comments.

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[4] INGAA's comments were supported by Tennessee Gas Pipeline Company, East Tennessee Natural Gas Company, Midwestern Gas Transmission Company, El Paso Natural Gas Company, Northern Natural Gas Company, and Great Lakes Transmission Company. United Gas Company also supports INGAA's comments, but filed its own additional comments.

Niagara Mohawk Power Corporation recommends that the comment procedure be used only if the settlement is opposed. Comments are necessary in order to determine if the offer of settlement is opposed or unopposed. It is important to note, however, that the participants may present their comments to the Presiding Officer orally, on the record. This procedure may be used in lieu of written comments to the Presiding Officer, and this procedure is encouraged.

Section 1.18(e)(3)

This subparagraph provides that uncontested offers of settlement before the Presiding Officer will be certified to the Commission together with the statement that the settlement is uncontested, any hearing record or pleadings which include support for the settlement offer. It also states that the Commission may approve uncontested offers of settlement upon a finding that the settlement appears to be fair and reasonable and in the public interest.

Florida Power & Light recommends that we change the language "the record, which shall include support for the offer of settlement" to "the evidentiary record as support for the offer of settlement." Tne company maintains that this change is necessary to insure that hearings are not held after an unopposed offer of settlement is filed. A modified verison of this recommendation is adopted.[5]

Both PSNY and Niagara Mohawk seek clarification of the word "support" when used in reference to unopposed offers of settlement in this subparagraph. Under the rule as modified, certification of an uncontested offer of settlement must include whatever matter in the record or pleadings supports the offer. However, as recommended by PSNY, it is a matter for the Presiding Officer to determine to what extent a compromise requires support in order for the Commission to make an adequate evaluation of the unopposed offer of settlement. The rule is clear, however, that substantial evidence is not required as support for unopposed offers of settlement.

INGAA suggests that the Commission specifically disallow comments to the Commission on an unopposed offer of settlement once that unopposed offer of settlement is certified to the Commission. This is unnecessary, since nothing in the rule allows or can be interpreted to allow the filing of such comments after certification of an unopposed offer of settlement by Presiding Officer. INGAA suggests that a certified offer of settlement should become a final Commission order if no adverse comments are received by the Commission within 35 days of certification. Under the new regulation the Commission plans to expedite unopposed offers of settlement. The Commission should not be bound by the recommended restriction. The Commission reserves its discretion to review each settlement agreement certified to it.[6] The requirement that an offer of settlement include a proposed Commission order will assist the Commission in acting expeditiously on unopposed settlement.

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[5] Tenneco requests that the Presiding Officer be given full discretion to require additional evidence in support of an unopposed offer of settlement. This is permitted by the rule.

[6] For this reason, the Commission provided in this rule that the Presiding Officer merely certify the settlement agreement to the Commission, rather than issue an initial decision approving an unopposed offer of settlement.

Section 1.18(e)(4)

This subparagraph provides for the handling of contested offers of settlement. Those filed with the Commission may be decided on the merits if the record contains substantial evidence on which to base a reasoned decision. If it does not, or if the contested issues cannot be severed, the Commission will order further procedures to obtain sufficient evidence or other appropriate procedures.

If comments on an offer of settlement were filed with the Presiding Officer who then determines that the offer was contested, the Officer may certify all or part of such offer to the Commission. However, if an offer was contested by any party, it may be certified only if (A) all parties concur on a motion for omission of the initial decision or the Presiding Officer finds that no contested issue of material fact remains; (B) the Presiding Officer determines the record contains substantial evidence from which the Commission may reach a reasoned decision on the merits of the contested issues; and (C) all parties have had an opportunity to avail themselves of such rights as they may have with respect to the opportunity to present evidence and cross-examine opposing witnesses. Severable, uncontested issues may be certified immediately to the Commission for decision.

Northwest Pipeline suggested additional procedures in lieu of those provided in the proposed rule which the Commission believes would add unnecessary and time-consuming steps in the proposed procedure by providing for notice of "partial certification" of a settlement and by disallowing certification of uncontested portions over one participant's objections.

Continental Oil Company recommends that the Commission allow a Presiding Officer to certify an offer of settlement even if one participant refuses to present evidence, to cross-examine other witnesses, or to waive its right to further hearing, if the Presiding Officer decides that there is adequate record evidence to decide the contested issues on the merits. The purpose of the rule is to require that each participant agree to the proposed offer of settlement, seek the appropriate administrative remedies available to him before the Presiding Officer, or waive its right to those remedies. Thus the rule reflects Continental's suggestions. If a party objecting to a settlement declines to pursue his right to present evidence or cross-examine, the party has had an opportunity to exercise his rights and the Presiding Officer may then certify the contested settlement to the Commission. Unless every party does this, one party, who has not voiced an objection to the offer of settlement or pursued its procedural rights before the Presiding Officer, may seek to oppose an offer of settlement before the Commission and delay the decision-making process. It is this situation which the Commission wishes to eliminate by amending the procedures for the submission of settlement agreements.

INGAA and United Gas Company recommend that, in the event that a participant opposes an offer of settlement, the participant present evidence as to the "substantial adverse impact on the public interest that would result if that portion of the settlement objected to is not modified." The Commission rejects this recommendation. This would be inconsistent with statutory requirements, as it places the burden of going forward on the contested issue on the participant contesting the issue. Both the Natural Gas Act and the Federal Power Act provide that a person filing an application for a change in rates, or for a certificate, must bear the burden of coming forward with evidence and proving that the approval of its application is just and reasonable or in the public interest. An offer of settlement does not modify that burden. It is for the offeror, not the offeree, to show that approval of the offer of settlement would conform to statutory requirements. The new rule specifically provides that as long as there is substantial evidence in the record on which a reasoned decision can be made on the contested issues, *and* each of the participants have been afforded due process of law, no further proceedings before the Presiding Officer are necessary, and he may certify the offer of settlement to the Commission.

Section 1.18(e)(5)

This subparagraph reserves to participants their procedural rights in the event that the Commission does to approve an uncontested offer of settlement as it is certified or filed with the Commission. Several parties argue that the word "Substantially" be deleted from this subsection, so that a participant will be deemed to have reserved its rights to a hearing if the Commission imposes any condition upon an offer of settlement. The Commission agrees and has modifed the proposed rule accordingly.

Miscellaneous

Mobil Oil Company and the Missouri Public Utilities Company both suggest procedures for expedited Commission review of certified offers of settlement. The Commission intends to give special and expedited consideration to all offers of settlement, once they are certified or filed with this Commission. *See* § 1.18(e)(3).

Effective Date

Section 553(d)(3) of the Administrative Procedure Act requires publication of a rule in the Federal Register not less than 30 days before the effective date of a rule unless good cause exists for an earlier effective date. The Commission finds that good cause exists to waive the effective date provisions of the Administrative Procedure Act. The rule is intended to simplify and expedite the Commission's settlement procedures. Both the Commission and regulated parties have an interest in facilitiating the settlement process so that an expeditious handling of settlements can result. Such expedition will reduce the Commission's caseload and also resolve disputes between parties faster. Accordingly, the Commission rule is effective June 15, 1979 and applies to offers of settlement filed on or after that date. Offers of settlement filed before June 15, 1979 will be considered under the Commission's settlement procedures in effect prior to promulgation of this rule.

(Department of Energy Organization Act, 42 U.S.C. 7107 *et seq.*; E.O. 12009, 42 FR 46267; Administrative Procedure Act, 5 U.S.C. 551 *et seq.*; Natural Gas Act, 15 U.S.C. 717 *et seq.*; Federal Power Act, 16 U.S.C. 792 *et seq.*; Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350; Public Utilities Regulatory Policies Act of 1978, Pub. L. 95-617, 92 Stat. 317.)

In consideration of the foregoing, Parts 1 and 2, Subchapter A, Chapter I of Title 18 of the Code of Federal Regulations, is amended as set forth below.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,062]

44 F. R. 37491 (June 27, 1979)

18 CFR Parts 270, 273

[Docket No. RM79-53; Order No. 36]

Natural Gas; Collection Authority; Refunds

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rules.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is issuing final regulations implementing section 503(e) of the Natural Gas Policy Act of 1978 (NGPA) which deals with the interim collection of the maximum lawful price. Section 503(e) permits interim collection, subject to refund, of those prices for certain categories of natural gas for which a determination of eligibility is made by a jurisdictional agency, subject to review by the Commission.

EFFECTIVE DATE: June 19, 1979.

ADDRESS: All filings should reference Docket No. RM79-53 and should be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Thomas P. Gross, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 (202) 275-0422.

SUPPLEMENTARY INFORMATION:

I. Background

On December 1, 1978, the Federal Energy Regulatory Commission (Commission) issued interim regulations implementing the Natural Gas Policy Act of 1978 (NGPA). (43 FR 56448). Part 273 of the Interim Regulations established procedures for interim collection authorized by Section 503(e) of statutorily prescribed prices of the NGPA. Section 503(e) permits interim collection, subject to refund, of those prices for certain categories of natural gas for which a determination of eligibility is made by a jurisdictional agency, subject to review by the Commission. These categories are new natural gas and certain OCS gas (as defined in section 102 of the NGPA), natural gas from new onshore production wells (section 103), high-cost natural gas (section 107) and stripper well natural gas (section 108).

Part 273 was divided into three subparts: general provisions, interim and retroactive collection procedures, and procedures for refund guarantees and refund payments. Subpart A contained provisions which dealt with private contractual rights, a definition of final determination, requirements for filing an annual report of collections and refunds and a cross reference section. Among other information, the annual report required by § 273.103 sought detailed information on collections subject to refund undertakings and surety bond or escrow accounts. It also required information as to refunds paid and copies of releases from the purchasers on an annual basis. This order promulgating the final regulations deletes the reporting requirements and imposes the requirement that sellers making interim collections retain records of such collections for a period of three years after the termination of the interim collection period.

A number of comments requested the Commission to explain who is required to make filings under Part 273. Section 273.103 has been changed to clarify these requirements.

Subpart B established specific rules for interim and retroactive collections. The transitional rule set forth in § 273.201 expired March 1, 1979. Accordingly, after an application for determination has been filed with the jurisdictional agency, the seller should use the procedure established by § 273.202 to collect, subject to refund, a price not in excess of the maximum lawful price for the category for which the application is made.

After the jurisdictional agency issues its notice of determination of eligibility for the well from which the sale is being made, § 273.203 authorized collection, subject to refund, of the price established by that initial determination pending review by the Commission. This section required the seller to file with the Commission and the jurisdictional agency a notice of interim collection. This filing has now been eliminated unless the seller did not file the information specified in § 273.202.

If as a result of the jurisdictional agency determination, the maximum lawful price exceeds the price collected for deliveries from the period beginning on the date of filing for the determination and ending on the date the determination becomes final, then § 273.204 authorizes the seller to retroactively collect this difference. Several changes have been made in this section.

Subpart C established the general refund obligation and procedures to refund any interim collections with interest after a final determination that a first sale did not qualify for a price already collected. In particular, § 273.302(c) required the seller to secure by surety bond or escrow account the portion of the price to be collected under § 273.202 which exceeds the price specified in § 273.201(a)(1) for new wells or, in the case of any other well, the portion which exceeds the otherwise applicable maximum lawful price unless the purchaser has executed a waiver of this requirement. This order modifies these provisions, and provides that the surety bond and escrow obligations are required only if the purchaser determines that they are necessary.

II. Summary of Comments and Revisions to Part 273

A. Subpart A—§§ 273.101–104

Subpart A sets forth general provisions regarding private contractual rights, a definition of final determination, annual reporting requirements and a cross reference section. Very few comments were received on these sections. Several comments suggested that the reporting requirements of § 273.103 were unnecessary and duplicated other ongoing reports.

Upon reconsideration, the Commission has determined that the filing of annual reports is unnecessary and that these reporting requirements should be deleted. However, the Commission believes that the information necessary to monitor compliance with Part 273 must be retained. Accordingly, § 273.302(d) is amended to require any seller who makes interim collections under Subpart B to retain records of such collections for a period of three years after the expiration of the interim collection period.

Section 273.102 provided a definition of final determination for purposes of Part 273. This section has been amended to define "eligibility determination" and the time at which an eligibility determination becomes final. The Commission expects this definition to clarify when a determination by a jurisdictional agency and a Commission finding, affirming, reversing, or remanding a jurisdictional agency determination becomes final. Those changes which are made in Part 273 to reflect the definitions in this section are discussed in more detail in the context of those sections.

A number of comments stated that the Interim Regulations do not specify which party is responsible for making filings under Part 273; i.e., whether the operator should file for all co-owners or whether all co-owners should file for themselves. The comments suggest this has created confusion in the industry and has resulted in some operators' filing to cover all of the working interests in their wells and many working interest owners' filing to cover only their own interest. In this regard, it is noted that some of the jurisdictional agencies will only allow the operator of a well to file a request for a determination.

Section 273.103 has been changed to clarify the filing requirements in general. All sellers making interim collections are responsible for filings. To address the most common question, the revisions make clear that any seller owning a working interest in a well and any seller owning a royalty interest in a well who takes his royalty payment in kind and sells the natural gas is required to make the filings required by this part. It is recognized that a seller may wish to designate another to make the filings on his behalf. This section allows the seller to designate any other working interest owner of the well, the operator of the well, or a royalty interest owner in the well to make these filings. The operator of the well making such filing may or may not be a working interest owner. Any person who submits a filing on behalf of a seller assumes the refund obligation for himself and for all those on whose behalf the filing is made.

Although this section allows the parties to agree to a filing arrangement suitable to their circumstances, it does not preclude a seller from making his own filing if he so chooses. If the seller designates another to make the filing on his behalf, the seller is not relieved of the obligation to make the required filings unless the filing is in fact made by the designated person. The Commission suggests that the sellers, in accordance with these requirements, select a filing arrangement suitable to their own circumstances. Furthermore, any filings made pursuant to Part 273 before the promulgation of this regulation will not be held deficient for failure to comply with this section.

B. Subpart B—§§ 273.201–273.204

Section 273.201 established a transitional rule which expired March 1, 1979. It allows a seller to charge and collect the prices specified in § 273.201(a) beginning on the date he satisfied the filing requirements of § 273.201(c) and ending when the Commission received notice of a jurisdictional agency determination, provided he filed an application for determination with the jurisdictional agency by March 1, 1979. This order deletes the table of maximum lawful prices in this section, and amends this section to refer to the table listed in § 271.902. One comment pointed out that the regulation does not specify what happens when the seller fails to file an application for determination with the jurisdictional agency by March 1, as required by § 273.201(c)(1)(iii).

We agree that the regulation is silent on this point. However, assuming that the seller made a filing with the Commission pursuant to § 273.201, the seller is obligated to file or cause to be filed an application for a determination with the appropriate jurisdictional agency. If such a filing is not made, the seller would be obligated to refund the collected monies in excess of the otherwise applicable maximum lawful price, and in some cases, may be subject to enforcement action.

A number of other comments were received regarding the scope, applicability and filing requirements in § 273.201. The transitional rule in this section reflected the statutory provisions of section 503(e)(1) of the NGPA. Since the rule expired by law as of March 1, 1979, these comments are not discussed. To the extent the comments raised issues which are also applicable to other sections of Part 273, they will be included in discussions of those sections. The transitional rule is retained to avoid confusion over the amounts to be collected and the period of collection authorized by it. No new filings may now be made under that rule.

After an application for determination has been filed, a seller may use the procedure established by § 273.202 to collect, subject to refund, the maximum lawful price for which the sale is claimed to be eligible. Several comments requested that the collection period begin December 1, 1978, rather than the date the application was filed if a petition for determination had been filed by March 1, 1979. The comments allege this would permit prompt collection of the monies and avoid accounting problems associated with the retroactive collection procedures.

The Commission does not find that there is a genuine need to change the interim regulations in the manner suggested. In many, if not all, cases the funds involved will not be substantial due to the short time involved and the collection of the price specified in § 273.201 on December 1, 1979 if an application under that section had been filed. Also the seller is ultimately entitled to collect the price for which he qualifies in addition to carrying charges (to the extent they have been agreed upon) by using the retroactive collection procedures.

Section 273.202(b) states that the period of collection shall end 18 months after the first delivery for which collection is made under § 273.202 (12 months for deliveries beginning on or after May 1, 1979) or on the date the Commission receives notice of the jurisdictional agency determination, whichever is earlier. Several comments noted that the 18-month period (or 12-month period where appropriate) is unreasonable since it is conceivable that a jurisdictional agency may not make a determination within this time period.

First, we note that this order amends the regulation to reflect that the applicable period of collection for first deliveries is now 12 months since the April 30, 1979, date is passed. As to the reasonableness of the period of collection, this issue was addressed in the preamble to the Interim Regulations where the Commission took the position that the limitation is both reasonable and necessary. Even with the backlogs they now have, there is no evidence at this time that jurisdictional agencies will require longer periods of time in which to make determinations. If it becomes apparent that the time limitation is likely to cause a problem, we may consider a revision of the rule. We note, however, that some time limitation is necessary to insure that consumers and purchasers of gas do not, for an unduly long period, pay prices in excess of those ultimately determined to be permitted under the law. It should also be noted that retroactive collections under § 273.204 are available after a final determination. The reference in this section to § 275.201 has been corrected to § 274.104, which is the section providing for notice to the Commission. The same change is also made in § 273.203(b).

Two comments noted that the regulation does not specify what price can be charged at the end of the 18 month (or 12 month) period. As noted above, the Commission expects that most jurisdictional agency determinations will be made within the specified period. However, if the question should arise, the seller would be limited to the otherwise applicable maximum lawful price.

Another comment suggested that where the first delivery was on or before the last day of April, 1979, it is not clear whether the interim collection lasts a maximum of 18 months, or until the date of the jurisdictional agency determination, or a maximum of 12 months for first deliveries after May 1, 1979. The Commission believes the regulation is clear on this point. The period of collection is 18 months after the first delivery for deliveries made before May 1, 1979, 12 months for deliveries on or after May 1, 1979, or in both instances, until the jurisdictional agency makes a determination.

Section 273.202(c) established a special limitation on the period of collection. As originally promulgated in the December 1, 1978 Interim Regulations, this section suspended collections after March 1, 1979 unless the Commission was notified in writing that the jurisdictional agency had authority to process applications for determinations and was making such determinations. After reviewing a number of comments on this limitation, the Commission extended the deadline to April 1, 1979. Because substantially all jurisdictional agencies are making the determinations, the Commission believes that adequate start-up time has been allowed and does not intend to grant further extensions. To provide for those few cases where programs have not yet been started but may be necessary, this section is amended to provide that no filing for interim collection may be made under this section unless the jurisdictional agency has filed a report with the Commission pursuant to § 274.105 and has notified the Commission that the agency has authority to process the applications for determination. A similar limitation on retroactive collections is set forth in § 273.204(b). These changes do not affect collections made prior to the promulgation of these regulations.

Section 273.202(d)(1)(iii) requires service upon any purchasers of the filing made under § 273.202. One comment noted that 18 CFR 1.51, referenced in the regulation, refers to an official service list maintained by the Secretary, and is inappropriate. We agree with this comment and have changed this section to require the seller to file a statement certifying that the filing has been served upon each purchaser.

Two comments noted that the purchaser is not notified of the actual filing date with the jurisdictional agency or the Commission. This filing date is important since it triggers the commencement of interim payments.

We agree that § 273.202(d)(1)(iii) does not require notice to the purchaser of the filing date. However, there are substantial administrative problems involved in requiring notification to the purchaser of the actual filing date of a document. Considering the need for the information and the ability of individual purchasers to acquire it, and balancing this against the burden which the Commission would have to impose upon the seller, the jurisdictional agency, or the Commission itself, we conclude that this matter is best left to be resolved between sellers and purchasers. Sellers should, of course, make this information available to purchasers on request.

One comment noted that the information required to be served on the purchaser does not relate the interim collection price to particular production from a particular well. None of the information required to be served on the purchaser identifies the gas purchase contract, the point of delivery, or the metering arrangement.

First we not that FERC Form 121 which is provided to purchasers, does contain the contract date. Also, if the gas sales contract was on file with the Commission as a jurisdictional FERC Gas Rate Schedule on November 8, 1978, the seller will so state. In the alternative, the purchaser can always contact the seller and request more specific contract identification. We will make one change in response to this comment. Section 273.202(d)(1)(v) is amended to require the seller who has a small producer certificate to provide the purchaser with the certificate docket number so that the purchaser may refer to the certificate application and identify the gas sales contract.

Section 273.202(d)(1)(i) requires the seller to file a statement under oath that be believes the gas sold qualifies for a maximum lawful price not less than that to be collected. One comment suggested that this could be done on a one time basis with a single oath statement. This suggestion will not be adopted. The Commission believes that the statement under oath indicates that the seller has carefully considered the specific filing. In view of the very small burden on sellers caused by this requirement, we see no reason to alter it at this time.

Section 273.202(d)(1)(v) requires a statement by each seller as to whether the gas was committed or dedicated to interstate commerce on November 8, 1978. One comment indicated that this requirement is unnecessary because the dedication or nondedication of gas on November 8, 1978, has no bearing on the eligibility of gas for rates to be collected under this section.

The Commission believes that the statement does not create an undue burden and is necessary so that interstate pipelines and other interested parties may be made aware that an NGPA filing has been made for gas previously sold under the provisions of the Natural Gas Act (NGA). Furthermore, since compliance with the filing requirements of § 273.202(d) is deemed to satisfy the requirements of 18 CFR 154.94(b) concerning producer rate change filings, it is necessary that the Commission receive this information.

Section 273.202(e) prevents further filings under § 273.202 for any sale from the same well upon termination of the interim collection authority for any sale from that well. Several comments requested an amendment to allow for the situation where a particular well which had previously qualified as a stripper well and subsequently lost its qualification because of over-production, later requalified as a stripper well. As presently written, § 273.202(e) would prevent a refiling for interim collection.

This suggestion was considered before promulgating the Interim Regulations and rejected on the basis that the seller may be eligible to use the provisions of § 273.204 to retroactively collect the maximum lawful price back to the date on which the later application was filed. Since the Commission adheres to this reasoning, no change is made in the regulation.

After the jurisdictional agency has determined that natural gas qualifies for a particular maximum lawful price, § 273.203 authorizes the seller to charge and collect this price, provided the seller files with the Commission, the jurisdictional agency, and the purchaser notice of the interim collection pending Commission review of the jurisdictional agency determination. Several comments stated that these filings already duplicated filings made pursuant to § 273.202 and should be eliminated. One comment suggested that since § 273.204 requires the jurisdictional agency to give notice to the Commission of the jurisdictional agency determination, the jurisdictional agency should notify the purchaser at the same time it notifies the Commission. Another comment suggested that further filings after a jurisdictional agency determination should be required only if the jurisdictional agency rejects the seller's application in whole or in part.

The Commission generally recognizes the issues raised by these comments. Accordingly, we amend § 273.203 to require the seller to file with the Commission the information specified in § 273.202(d)(1)(i)–(v) only if the information has not previously been filed. Purchasers should make whatever arrangements they deem necessary to be informed of jurisdictional agency determinations. Furthermore, purchasers are reminded that the Commission publishes notices of its receipt of determinations in the Federal Register.

Section § 273.203(b)(2) requires that the period of collection end on the date the jurisdictional agency determination becomes final or six months after the date of remand to the jurisdictional agency by the Commission. Based on the new definition of final eligibility determination in § 273.102, this section has been amended to provide that the period of collection ends when the eligibility determination becomes final. New language has been added to this subparagraph to clarify that in the case where the jurisdictional agency determination is reversed by final finding of the Commission, the period of collection ends on the date of such final finding.

One comment requested clarification as to what price may be collected after the 6-month period expires. If authority to make collections under this section expires at the end of the 6-month period or due to Commission reversal of a jurisdictional agency determination by a final finding pursuant to § 275.202(e), the seller may charge the otherwise applicable maximum lawful price.

Section 273.204 authorizes the retroactive collection of the finally determined price for all first sales of gas delivered after the application for determination was filed. Two comments questioned the Commission's authority to implement any retroactive collection regulation, arguing that section 503(e) of the NGPA does not specifically require retroactive collections. Two other comments submitted that the Commission has ample authority to implement retroactive collections.

This issue was considered in the preamble to the Interim Regulations. Retroactive collection was defended on the basis that it is not inconsistent with the statutory language and that it was discussed with approval in both the Statement of Managers and floor debate.

The Commission adheres to this position insofar as it feels that retroactive collections are necessary to allow the seller to collect the maximum lawful price to which he is entitled. It is recognized that retroactive collections are not explicitly mentioned in the statutory language of section 503(e) of the NGPA. However, the Commission believes that authority for retroactive collections is contained in the language of section 503(e) and is expressly supported by the legislative history of this section.

Section 273.204(a) and (b) originally established a March 1, 1979, deadline for the filing of an application with the jurisdictional agency in order to collect claimed prices as of December 1, 1978, and notification to the Commission by the jurisdictional agency that it has authority to process applications. Several comments requested an extension of this deadline. After reviewing these comments, the Commission, by order issued March 1, 1979, extended the deadline to April 1, 1979. The Commission believes that this extension provided adequate time for the filings and notifications required by this section. In order not to subject purchasers to long periods of uncertainty concerning their obligation to pay higher prices, no further extension will be made.

Section 273.204(a) allows retroactive collection from the time of filing with the jurisdictional agency to the date the determination becomes final. This section has been amended to reflect the definition of eligibility determination in section 273.102. Accordingly, where the jurisdictional agency determination is reversed or affirmed by a final finding of the Commission and the Commission's finding is no longer subject to judicial review, the seller may begin retroactive collection 45 days after such time, provided he complies with the other conditions in this section. In any other case, such as when an eligibility determination becomes final because it is no longer subject to remand or reversal by the Commission due to the expiration of the 45-day review period, the seller may begin retroactive collections 45 days after such time.

In cases where the application for determination was filed by April 1, 1979, the excess amount may be charged and collected for first sales of gas delivered on and after December 1, 1978. One comment suggested retroactive payments begin when deliveries commence; however, retroactive collections would be limited to a 60-day period prior to the date the application is filed with the jurisdictional agency.

The Commission believes that the procedures established by the regulations are reasonable and ultimately entitle the seller to collect the full price to which he is entitled. The transitional rule allowed both buyers and sellers to familiarize themselves with the new procedures established by the Commission's regulations. To the extent possible the rules should provide consumers with certainty regarding their financial obligations. Current procedures establish this certainty by requiring notice of the price sought and a clearly ascertainable commencement date viz., the filing of the application for a determination.

Section 273.204(c)(4) provides that retroactive collections may be made only to the extent "permitted" by the sales contract. Two comments suggested that this section should be amended to allow retroactive collections only where "expressly authorized". This suggestion will not be adopted. As currently written, the regulation allows the parties to either adopt a contract provision expressly authorizing retroactive provisions or to interpret their existing contract to permit such payment.

Several comments noted that retroactive collections could result in large contingent liabilities on the pipeline purchasers and result in cash flow problems. One comment noted that the regulations do no specify whether the payment is to be made in a lump sum or spread over time.

These issues were considered in the preamble to the Interim Regulations. The Commission refused to adopt a single retroactive collection plan on the basis that these details should be left to the discretion of the parties and the terms of the sales contract. There is no reason to change this policy. If a pipeline wishes to protect itself from cash flow problems, and appropriate provision may be added to the gas purchase contract. There is nothing in the NGPA or the Commission's regulations to preclude any purchaser from arranging a time payment plan for bills once they become due and owing.

Section 273.204(c)(2) prevents the seller from retroactively collecting the allowed price unless the seller "has paid to such purchaser all amounts due to be refunded under this subchapter * * *" One comment suggested inserting the words "or offset" after the word "paid." Section 273.302(e)(1) specifically prohibits offsetting the obligation by requiring the refund payment be made by cash or check.

This requirement was imposed for two reasons. First, under the NGA, refunds were permitted to be made either in the form of reduced prices or the delivery of additional gas. Use of offsets often delayed repayment of amounts to which consumers of gas were entitled. In addition, monitoring refund obligations was difficult and time consuming. The Commission believes that consumers should receive repayment of any excess prices as soon as possible. Accordingly, we do not adopt the suggestion in this comment and leave intact the requirement that refunds be made by check or cash within 45 days of the date they are determined to be required.

C. Subpart C—§§ 273.301–273.302

Subpart C establishes procedures to refund any interim collections with interest after a final determination that a first sale does not qualify for a price already collected. Two comments noted that since there is no prior eligibility determination for sales made pursuant to sections 105, 106(b), and 109 of the NGPA, these categories were exempt from the refund provisions of Subpart C. Accordingly, it was suggested that the Commission impose a general refund obligation to apply to these sales.

Section 270.101(e) establishes a general refund obligation for collections made under Subchapter H. This section, which has been changed to clarify the general refund obligation, would apply to sales made pursuant to sections 105, 106(b), and 109.

Section 273.301 establishes a general refund obligation. Today's order amends this section to make clear that the acceptance of proceeds by any person obligates such person and his successors, heirs, and assigns to comply with the general refund obligation. Accordingly, the refund obligation in this section results solely from the acceptance of proceeds. The obligation is not avoided by failure to make the required filings under Part 273 nor is it avoided or discharged by designating another to make the filings, whether or not the filings are made.

Section 273.302(b) required the seller to file either a general or specific agreement and undertaking to make refunds of monies subject to a refund obligation. These filings indicated that the seller was aware of the refund obligation. The Commission now believes that the filing of a separate document in the form of an undertaking to make refunds is unnecessary, and that the filing for interim collections specified in § 273.202 and § 273.203 should itself constitute the agreement and undertaking to make refunds.

Accordingly, § 273.302(b) is amended to provide that any filing for interim collection shall constitute an agreement and undertaking to comply with the refund provisions of Part 273. Where the filing was made on behalf of another pursuant to § 273.103, the person making the filing and all sellers on whose behalf the filing is made shall be subject to the undertaking to make such refunds. Section 273.202(d)(2) has been added to provide additional notice to persons who make filings under § 273.202 and § 273.203 of the refund obligation imposed by the regulations.

Section 273.302(c) required that the portion of the price to be collected under § 273.202 which exceeds the price specified in § 273.201(a)(1) for new wells be secured by a surety bond or placed in an escrow account. Similarly, any amount collected under § 273.202 which is in excess of the otherwise applicable maximum lawful price for any other well was subject to the same surety bond and escrow requirements. This section allowed the purchaser to waive this requirement so long as he executed a written agreement releasing the seller from this obligation.

Numerous comments opposed these requirements, labeling them unreasonable and unnecessary. Most comments urged the Commission to adopt a corporate guarantee or undertaking to make refunds. A procedure which has been used successfully under the NGA.

Some comments stated that the waiver provision in § 273.302(c)(1) gives the pipeline purchasers additional leverage during negotiations, while other comments suggested that the purchaser be given more assurance that the seller has complied with these requirements. It was also suggested that the Commission allow an exemption for small sales and small companies. One comment suggested that other less expensive financial instruments be allowed.

Similar comments were submitted with respect to § 273.202(d)(1)(iv), which requires the seller either to file with the Commission a statement certifying that the collections made under this section will be placed in an escrow account or secured by a surety bond or to file with the Commission an executed release from the surety or escrow obligation.

The Commission acknowledges that in some cases, because of relationships between purchasers and sellers, the purchaser will not feel the need for a surety bond or an escrow account to cover interim collections. However, because of the large amounts of money which may be collected on an interim basis and the large numbers of sellers who will be making such collections, we believe some safeguards should be available.

Accordingly, the amendment adopted does not abolish the surety bond or escrow account obligations, but retains these provisions as an optional requirement which may be imposed by the purchaser. The regulations are amended by deleting the requirement that the purchaser execute a written release. Accordingly, the Commission expects the purchaser to make an initial determination as to the credit-worthiness of the seller. In those situations where he is satisfied with the seller's ability to make refund payments, the repayment of funds would be subject to the general undertaking specified in § 273.302(b)(1).

In those situations where the purchaser feels that the potential refund monies should be secured in some manner, § 273.302(c) has been amended to provide that the purchaser may require the appropriate funds be deposited in an escrow account or secured by a surety bond in a form satisfactory to the purchaser. Since the purchaser may not deem the requirement imposed by § 273.302(c)(2) to be necessary, this subparagraph is deleted. The regulations do not provide for special exemptions for small companies or small sales. The reasons for exempting small companies or sales from other requirements such as reports, do not apply to the situation addressed in the regulations.

Several comments questioned whether collections made pending review of a determination are subject to the escrow or surety obligations. Since the jurisdictional agency has determined the price for which the natural gas qualifies, collections pending review of this decision are not subject to the escrow or surety obligations. However, such monies would be subject to refund if the Commission issues an order disallowing the higher rate.

Sections 273.302(e) and (g) set forth provisions regarding the refund payment and computation of the refund. These subsections have been amended to refer to the eligibility determination as defined in § 273.102. Accordingly, when an eligibility determination becomes final because a Commission reversal of a jurisdictional agency determination is no longer subject to judicial review, or, in any other case, because the jurisdictional agency determination is no longer subject to remand or reversal by the Commission, the refund payment is due within 45 days thereafter.

Today's order also amends § 273.302(e) to require the seller to file the original and two copies of a refund report which identifies the amount required to be refunded and the appropriate interest. The seller is also required to file with the Commission the original and two copies of a release from the purchaser which show that the refunds have been paid.

Section 273.302(e) specifies a fixed 9% per annum interest rate on the monies to be refunded. One comment suggested changing this interest rate every 6 months to track the prevailing interest rate. This order amends § 273.302(e)(1) so as to require the refund amount to be computed at the interest rate specified in § 154.102(c). In a previously issued Notice of Proposed Rulemaking (RM77–22), 44 FR 18046 (March 26, 1979), the Commission has proposed to change § 154.102(c), which, among other things, would tie the interest rate on carrying charges and refunds to the prime rate charged by commercial banks for short-term business loans. Section 273.204(c)(5) is also changed to specify that the interest rate at which carrying charges are computed is not to exceed the rate specified in § 154.102(c).

Section 273.302(f) sets forth provisions for the discharge of the bond, escrow, or undertaking obligations. This section is amended to refer to eligibility determination as defined in § 273.102. Accordingly, the obligation is not discharged until the eligibility determination becomes final pursuant to § 273.102(b).

Finally, one comment questioned whether in the case of gas committed or dedicated to interstate commerce on November 8, 1978, the term "otherwise applicable maximum lawful price" as used in § 273.302(c) refers to the applicable just and reasonable area or national rate under the NGA or to the applicable section 104 price under the NGPA. The phrase refers to the section 104 price or the section 106(a) price, whichever is applicable.

III. Public Procedures and Effective Date.

The regulations in Part 273 were originally proposed for comment in November of 1978 and issued as interim regulations on December 1, 1978 (43 FR 56448, Dec. 1, 1978). For 60 days thereafter comments were received and during that period public hearings were held on these regulations. By this process the Commission complied with the provisions of section 502(b) of the NGPA which requires that "[t]o the maximum extent practicable," an opportunity for the oral presentation of data, views, and arguments be afforded for certain regulations under the NGPA.

The amendments to Part 273 which are contained in this order have been promulgated after careful consideration of these comments.

Accordingly, the Commission finds that further notice and public procedure on these rules is unnecessary and impractical and that good cause exists to dispense with additional notice and procedure. Part 273, as amended, is effective as final regulations upon the date of issuance of this order.

(Natural Gas Act, as amended, 15 U.S.C. 717, *et seq.*; Natural Gas Policy Act of 1978, Pub. L. 95–621, 92 Stat. 3350; Department of Energy Organization Act, Pub. L. 95–91, E.O. 12009, 42 FR 46267.)

In consideration of the foregoing Part 270 and Part 273 of Subchapter H, Chapter 1, Title 18, Code of Federal Regulations issued as Interim Regulations (43 FR 56448, December 1, 1978) and amended by order of the Commission dated March 1, 1979, are promulgated as final regulations and amended as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,063]

44 F. R. 37499 (June 27, 1979)

18 CFR Part 281

[Docket No. RM79-15; Order No. 29-A]

Natural Gas Curtailment: Regulation for Implementation of Section 401 of the Natural Gas Policy Act of 1978

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: On May 2, 1979, the Federal Energy Regulatory Commission issued a permanent curtailment rule (44 FR 26855, May 8, 1979) which established a system of high-priority (Priority 1) and essential agricultural (Priority 2) use requirements and integrated them into the curtailment plans of interstate pipelines. The Commission has amended that rule to extend the dates for filing petitions for Priority 1 and 2 treatment. This amendment postpones until July 15, 1979, the filing dates for essential agricultural users, distribution companies, and pipelines.

DATES: Petitions must be filed by July 15, 1979.

FOR FURTHER INFORMATION CONTACT: MaryJane Reynolds, Federal Energy Regulatory Commission, Office of the General Counsel, 825 North Capitol St., N.E., Room 8000, Washington, D.C. 20426, (202) 275-4283.

SUPPLEMENTARY INFORMATION:

Background

On May 2, 1979, the Federal Energy Regulatory Commission ("Commission") issued a permanent curtailment rule (44 FR 26855, May 8, 1979) which established a system of high-priority (Priority 1) and essential agricultural (Priority 2) use requirements and integrated them into the curtailment plans of interstate pipelines. This new rule requires the reordering of curtailment priorities by November 1, 1979 and applies this treatment to deliveries of natural gas beginning on that date. The new rule requires considerable data gathering and reporting by end-users, distributors and interstate pipelines. Under § 281.211(b) of the new regulations essential agricultural users which seek Priority 2 treatment for their agricultural requirements of natural gas are required to file a request for Priority 2 treatment with all direct suppliers by June 15, 1979. Local distribution companies must review and forward these requests to their interstate pipeline suppliers by June 30, 1979 (§ 281.211(c)) and, if the pipeline purchases gas from downstream pipelines it must request reclassification of its Priority 2 entitlements from its supplier by July 15, 1979 (§ 281.211(d)). Similarly, direct sale customers and local distribution companies must report Priority 1 requirements to their direct suppliers no later than June 15, 1979. Interstate pipelines must report Priority 1 entitlements to their upstream suppliers by July 15, 1979. Under § 281.212, the interstate pipelines must then file draft tariff sheets and an index of entitlements with the Data Verification Committee ("DVC") and distribute these documents to customers. The DVC has from August 1 to September 23 to review the tariff sheets, index of requirements and the back-up data therefor.

On May 14, 1979 the United States Department of Agriculture ("USDA") issued its permanent rule establishing essential agricultural volumetric requirements. 44 FR 28782 (May 17, 1979). That rule modified the interim rule and determined that all essential agricultural users were entitled to one hundred (100%) percent of current requirements to meet their essential agricultural needs. The permanent curtailment rule incorporates the USDA rule—as well as its amendment of May 14, 1979—by reference. Consequently, under the Commission's permanent curtailment rule all essential agricultural users, as defined by USDA, are entitled to request current requirements for their essential agricultural uses.[1]

The Commission rule preceded the final USDA rule, and possibly there has been some confusion concerning the fact that the permanent curtailment rule incorporates the changes in the USDA rule. As noted previously, it does.

It has come to the attention of the Commission and the Department of Agriculture that many essential agricultural users have not become aware of the need to request Priority 2 classification by June 15, 1979.

It is essential that all requests for essential agricultural requirements be received by the local distributor before it reports its customer's requirements to its pipeline suppliers. Also, pipelines need the complete data before they can report to their upstream suppliers and prepare their index of requirements. Thus, if farmers or other essential agricultural users fail to petition their suppliers for priority treatment of their gas supplies by June 15, 1979, they may be foreclosed from the benefits that Congress intended to provide such users in terms of receiving natural gas in preference to all but high-priority users. Therefore, the Commission believes it would be advisable to extend by 30 days, to July 15, 1979, the date by which essential agricultural users must file requests with local suppliers. Since the compilation and transmittal of requests for Priority 2 status by local distribution companies and interstate pipeline suppliers depends on the initial filing by essential agricultural users themselves, the filing dates for these entities should likewise be extended. The dates for filing of Priority 1 data are also extended. However, the Commission believes it is important that to the maximum extent practicable the new curtailment plans be in place by November 1, 1979, in time for the winter heating season. Accordingly, no similar extension will be given to the DVCs. Rather the actual time given the DVCs will be shortened: they will receive the documents on August 30, 1979 and are scheduled to submit their report on September 23, 1979. However, the dates for filing protests with the DVC are extended. The Commission recognizes the possibility that the DVCs may need more than 3 weeks to review the data and if severe problems of timing arise either for a particular DVC or for all DVCs more time may have to be alloted to the DVCs.

Section-by-Section Analysis

The amendments in this rulemaking advance the filing dates in § 281.211 (a) and (b) by approximately one month. Paragraph (a) is changed in clause (i) of subparagraph 91) by extending the filing date from June 15, 1979 to July 15, 1979. Paragraph (a) is changed in clause (i) of subparagraph (2) by extending the filing date from July 15, 1979 to August 15, 1979. Paragraph (b) is changed in clause (i) of subparagraph (1) by extending the filing date for essential agricultural users from June 15, 1979 to July 15, 1979, in subparagraph (2) by extending the filing date for local distribution companies to July 30, 1979, and in subparagraph (3) by extending the date for requesting reclassification of entitlements by interstate pipeline purchasers to August 15, 1979.

Section 281.212 is changed in paragraphs (b) and (c) to provide an additional month, until August 30, 1979, for pipelines to serve indices of entitlement and draft tariff sheets.

Effective Date

Section 553(d) of the Administrative Procedure Act requires that publication of a rule be made not less than 30 days before its effective date unless *inter alia* a rule relieves a restriction or the agency finds good cause for more expeditious action. The amendments to § 281.211 and § 281.212 are intended to make it possible for essential agricultural users to exercise their rights to priority treatment of certain gas

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[1] Under the attribution provisions of § 281.209, in certain circumstances, a portion of essential agricultural requirements of a particular essential agricultural user may not be attributed to interstate pipeline suppliers.

supplies. In order that the intent of Congress that essential agricultural users be protected from curtailment of natural gas is carried out, the Commission believes that the June 15, 1979, deadline must be extended. Because the date is imminent, the Commission finds good cause to make the amendments to Part 281 effective immediately.

(Natural Gas Policy Act of 1978, Pub. L. 95–621. Department of Energy Organization Act, 42 U.S.C. § 7107 *et seq.*; E.O. 12009, 42 FR 46267; Administrative Procedure Act, 5 U.S.C. § 551 *et seq.*)

In consideration of the foregoing, Subpart B, Part 281, Chapter 1, Title 18 of the Code of Federal Regulations is amended as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,064]

44 F. R. 37500 (June 27, 1979)

18 CFR Part 294

[Docket No. RM 79–52]

Interim Procedures for Shortages of Electric Energy and Capacity; Interim Rule

AGENCY: **Federal Energy Regulatory Commission.**

ACTION: **Notice of interim rule.**

SUMMARY: **The Federal Energy Regulatory Commission is promulgating an interim regulation as a first step in implementing Section 206 of PURPA, which added a new Section 202(g) to the Federal Power Act. The interim rule requires public utilities to file with the Commission a summary of procedures to be used in the event of a shortage of electric energy or capacity. In addition, these utilities must notify the Commission of any anticipated shortage of electric energy or capacity.**

EFFECTIVE DATES: **June 27, 1979. Written comments must be filed by July 15, 1979.**

ADDRESS: **Send Comments to: Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426.**

FOR FURTHER INFORMATION CONTACT: **Adam Wenner, Federal Energy Regulatory Commission, Office of the General Counsel, 825 North Capitol Street, N.E., Room 8100–D, Washington, D.C. 20426, (202) 275–4210.**

SUPPLEMENTARY INFORMATION: **Outages of nuclear or other major power plants and possible unavailability of oil may contribute to shortages of electric energy or capacity thereby affecting the ability of certain utilities adequately to supply electric service to their wholesale customers during the 1979 summer peak periods. Some utilities facing the possibility of shortages this summer have informally advised the Commission of their energy and capacity capabilities. This interim regulation is intended to provide the Commission with similar information on a nationwide basis.**

Section 206 of the Public Utility Regulatory Policies Act of 1978 (PURPA) amends section 202 of the Federal Power Act (FPA) by adding a new subsection (g). That subsection provides that the Commission shall require each public utility to report to the Commission any anticipated shortage of electric energy or capacity which would affect the utility's capability of serving its wholesale customers. In addition, public utilities are required to submit to the Commission and to any appropriate State regulatory authority contingency plans respecting shortages of electric energy or capacity and circumstances which may result in such shortages. Finally, public utilities are required to accommodate any such shortages in a manner which gives due consideration to the public health, safety and welfare and to provide that all persons served directly or indirectly by each public utility will be treated without undue prejudice or disadvantage.

As an interim measure to prepare for possible shortages of electric energy or capacity this summer, the Commission finds it appropriate to take immediate action, in partial fulfillment of our responsibilities under the Federal Power Act, to issue interim regulations implementing the new section 202(g) of the Act.

In the near future the Commission will issue proposed rules implementing the remaining portions of section 202(g). At that time, we will request public comment on our proposed rules and consider those comments in our deliberative process prior to implementation of the rules. However, the Commission finds that the possibility of shortages this summer requires that, as an interim measure, we act with an immediately effective interim regulation without first receiving public comments.

Summary of the Regulation

While shortages of energy and capacity affect firm and nonfirm power wholesale customers of public utilities, firm power customers are most directly affected by such shortages. Accordingly, for purposes of this interim rule, "anticipated shortages of electric capacity or energy" are defined in paragraph (a) as situations in which a public utility anticipates that, prior to September 30, 1979, it will be unable to meet the energy or capacity requirements of its customers, and this shortage will affect the utility's ability adequately to supply electric services to its firm power wholesale customers.

As a first step in the promulgation of regulations implementing Section 206 of PURPA, paragraph (b) of this interim regulation requires each public utility serving firm power wholesale customers to submit by June 29, 1979, a statement describing how it would accommodate shortages which might affect its wholesale customers. Each reporting utility must identify any agreement, law or regulation which might impair its ability to accommodate such a shortage. Each utility must file a copy of its statement with the appropriate State regulatory body and with each of its firm power wholesale customers.

Paragraph (c) requires any public utility which anticipates a shortage of electric energy or capacity immediately to report such anticipated shortages to the Commission, to appropriate State regulatory authorities, and to its firm power wholesale customers. In ascertaining its ability to meet anticipated shortages of electric energy or capacity, each utility should include in its calculation of energy or capacity, only the bulk purchased power or energy supply for which it has a contractual commitment and reasonable assurance of ultimate availability.

Effective Date

These regulations are being issued on an interim basis and made effective immediately. The Commission finds that its need to be advised of anticipated shortages and of utilities' procedures to accommodate such shortages constitutes good cause to find prior notice and public comment procedure to be impracticable and to waive publication not less than 30 days prior to the effective date. The Commission requests data, views or arguments with respect to these regulations. After evaluating the information received, the Commission will make any appropriate revisions to these regulations.

Written Comment Procedures

Interested persons are invited to submit written comments, data, views or arguments with respect to this proposal. An original and 14 copies should be filed with the Secretary of the Commission. All comments received prior to July 13, 1979, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, 825 North Capitol Street, NE, Washington, D.C., during regular business hours. Comments should be submitted to the Federal Energy

Regulatory Commission, 825 North Capitol Street, NE, Washington, D.C. 20426, and should reference Docket No. RM79-52.

[¶ 30,065]

44 F. R. 38834 (July 3, 1979)

18 CFR Part 154

[Docket No. RM79-22; Order No. 23-B]

Order Adopting Final Regulations Establishing Protest Procedures Regarding Blanket Affidavit Filings and Interim and Retroactive Collection Filings

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Regulations.

SUMMARY: The Commission is issuing final regulations establishing protest procedures regarding blanket affidavit filings under § 154.94(h) and interim and retroactive collection filings under § 154.94(i).

EFFECTIVE DATE: August 15, 1979.

FOR FURTHER INFORMATION CONTACT: Phil Yates, Office of the General Counsel, Federal Energy Regulatory Commission, Room 4308-D, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 275-4845.

SUPPLEMENTARY INFORMATION:

I. Introduction

On March 13, 1979, Order No. 23 was issued in Docket No. RM79-22.[1] That order set forth the Commission's administrative view regarding the impact that the Natural Gas Policy Act of 1978 (NGPA)[2] would have on the operation of "area rate clauses."[3]

In Order No. 23, the Commission stated:

> the Commission's regulations, * * * do not preclude the operation of price escalation provisions in a contract, the terms of which specifically permit escalation to Congressionally or legislatively authorized prices or which specifically reference Natural Gas Policy Act prices. Also, the Commission will, in the absence of specific contractual language to the contrary, generally interpose no objection to the parties to an interstate contract ascribing an interpretation to an area rate clause in its contract as would authorize escalation to, and collection of, the Natural Gas Policy Act price ceilings.
>
> In the event that interstate pipeline purchasers contest the use or reliance by sellers on area rate clauses in their contracts, the Commission will provide an opportunity to protest. Once a protest to contractual authorization is submitted, the Commission will then consider the matter and attempt to state its view. Other parties in interest, including state commissions, local distribution companies and other aggrieved parties will be permitted to participate in any such proceeding. Also, such parties may protest the utilization of area rate clauses even in the face of agreement among the parties to the contract as to the interpretation which should be ascribed to such clauses. In this event, however, the Commission advises that considerable weight will be given to the interpretation ascribed to the contract by its parties. (footnote omitted)[4]

The position announced in Order No. 23 was a practical one. The Commission concluded that certain area rate clauses may be triggered by the NGPA and that others may not. However, it was simply impossible for the Commission to examine each interstate natural gas contract in the proceeding in which Order No. 23 was issued. This order establishes the procedure by which the Commission will determine contractual authorization to collect NGPA rates in first sales subject to the Natural Gas Act (NGA).[5]

Many applications for rehearing of Order No. 23 were received which challenged the contract law principles underlying Order No. 23. Specifically, many indicated that the Commission could do no more than look to the "four corners" of the contract to ascertain the contract's meaning.

Of course, in any dispute involving the interpretation of a contract, the "four corners" of the contract must be the initial point of departure. However, modern contract law principles allow reference "not only to the 'four corners' of the contract, but also to the circumstances surrounding the execution of the contract."[6]

Under the procedures set out below, the Commission will first look to the document itself in reviewing contracts involving natural gas subject to the jurisdiction of the Commission under the NGA. If, however, other factors need be considered to interpret the contract, these procedures will afford an opportunity for the presentation of evidence respecting such factors.

Orders 15,[7] 15A,[8] and 25 [9] established special Natural Gas Act section 4 rate-change filing procedures for purposes of collecting the higher rates permissible under the NGPA. Under these orders, the requirements of NGA section 4 were deemed to be satisfied by either a blanket affidavit or interim or retroactive collection filing.[10] Protests could be made with respect to any of these filings. By this order, the Commission establishes "a general protest procedure in which parties in interest can petition the Commission for a specific determination as to whether a particular contract clause constitutes the requisite authority to charge and collect Natural Gas Policy Act rates."[11]

II. Discussion of Comments

On May 2, 1979, the Commission issued a Notice of Inquiry in this docket, requesting comments on the appropriate procedure to be utilized in evaluating protests to contractual authority. Specifically, comments were requested on whether a pipeline's Purchased Gas Adjustment (PGA) hearing would be an appropriate forum to deal with such protests, and whether natural gas contracts could be grouped generically for decisional purposes.

Seventeen comments were received to our Notice of Inquiry. The vast majority of them strenuously objected to the use of the PGA proceeding as the forum to resolve contractual disputes. They were more evenly split on the question of generic grouping of contracts; potential third-party protestors favored generic grouping, producers and pipelines were generally opposed.[12]

The Commission considered the alternative of examining the question of contractual authorization in the context of pipeline PGA proceedings. While the Commission is of the view that the question will lend itself to resolution on a pipeline-by-pipeline basis, the PGA proceeding is not the proper forum. The specialized nature of contractual authorization questions and the length of time necessary to dispose of them would, as most comments point out, complicate proceedings. Therefore, the Commission will sever these questions from the PGA proceedings and require that evidence as to contractual authorization which would have been submitted in the PGA proceeding be separately presented in the protest proceedings established under this order.

The Commission cannot make a general rule involving the appropriateness of grouping contracts for purposes of decision. The procedure adopted herein requires that decision to be made on an *ad hoc* basis by the Chief Administrative Law Judge.

Some comments indicated that the protest procedure under our present regulations was adequate. Others made specific proposals concerning the appropriate procedure to handle protests to assertions of contractual authority. The Commission has concluded that the present procedure is inadequate, largely because it does not afford potential protestors adequate opportunity to focus on specific contracts, file specific protests, and have the parties' assertions evaluated.

Several commentors would have the Commission require producers to make new filings for each contract, in which the producer would state the foundation for his belief that contractual authority to collect the NGPA maximum lawful price exists. Each comment suggested slightly different ways to process protests to these filings.

As more fully discussed below, the Commission will require pipelines, not producers, to file this additional information. However, certain aspects of the procedures suggested by the comments have been adopted.

Three comments asserted that a limited number of hearings be held. They suggested a large proceeding dealing with a representative sampling of natural gas contracts, or a few proceedings to set precedents. One Public Service Commission went so far as to say it had "no interest in relitigating for each rate schedule questions which, as a result of test cases, are settled insofar as the Commission is concerned."

The Commission cannot accept these suggestions. Despite the administrative burden, the Commission feels that it must provide an opportunity for an interested party to challenge any contract which that party feels does not constitute contractual authority to charge the NGPA rate.

One comment suggested a "bifurcated" procedure, one for "typical" area rate clauses where no hearing would be provided, and another procedure for all others which would provide for hearings. The Commission has adopted this procedure, although the distinction between those protests which can or cannot be resolved with a hearing is not based on whether or not the contract is "typical." It is questionable if any escalation provisions could accurately be characterized as "typical." Therefore, the initial distinction will be made based on whether the language of a particular contract is inconsistent with the claim of the parties to the contract that there is authority to collect the higher NGPA rate.

If the language of the contract is inconsistent with that interpretation, a hearing will be ordered. If there is no inconsistency, the protest will be summarily dismissed, unless specific evidence is filed which may explain or modify the text of the contract.[13] To the extent possible, contracts with similar language will be dealt with generically.

One comment suggested that the hearing officer be allowed to decide specific procedural questions involving a protest before him. This suggestion has been adopted. The Commission has delegated to the Chief Administrative Law Judge the responsibility to set protests for hearing, sever and consolidate proceedings, and certify questions to the Commission. Further, the Administrative Law Judge to whom a particular protest is assigned may be authorized by the Chief Administrative Law Judge to issue similar procedural orders regarding that protest. Such a device was necessary to allow an expeditious treatment of what is anticipated to be a large volume of protests.

Several parties suggested that the burden of proof in any protest proceeding should be on the producer rather than the protestor. We specifically address this issue below.

III. The Procedure

The Commission has concluded that evidence claimed to authorize increased rates due the passage of the NGPA should be made available for use in the protest proceedings respecting NGA rate increase filings under 18 CFR 154.94 (h) or (i). However, we have determined that jurisdictional pipeline companies should submit such evidence rather than producers. This decision is predicated upon the Commission's view that interstate pipelines are in a much better position to supply the needed evidence than are producers. First, we presume that the pipelines in the regular course of business will review relevant contractual provisions prior to making a decision whether to protest the blanket affidavit or interim or retroactive collection filings. Second, there are far fewer interstate pipelines than producers; thus there will be fewer filings. Because of the large number of producers, it would be difficult to assure that all of the needed evidence would be submitted in a timely fashion. Third, because some producers conduct extremely small operations, imposing an additional filing burden on them would create more of a hardship than upon interstate pipelines. Fourth, it is anticipated that interstate pipeline contracts will fall into a limited number of generic categories, thus allowing protests to be made on a generic basis in some cases. Finally, interstate pipelines are in a much better position than producers to provide interested parties with copies of such evidentiary filings, much in the same manner as they presently are required to serve their customers with their PGA filings.

Each pipeline which purchases natural gas for resale must file with the Commission the following evidence: (1) The rate schedule number, (or, if there is none, the date of the contract) for each of its contracts for which the seller has made a rate increase filing under 18 CFR 154.94 (h) or (i); (2) the name of the seller for each such contract; (3) the section or sections of the NGPA which are applicable to the first sales under each contract; (4) the text of the contractual provisions as well as any other evidence [14] which the pipeline believes constitutes or may constitute the contractual authority to escalate the price to the NGPA ceiling. Further, the pipeline shall list those contracts for which the pipeline and seller disagree on the question of contractual authority to collect a higher rate under the NGPA.

These evidentiary submissions are required to be filed before August 15, 1979, with the Commission as well as with those State commissions and pipeline customers that specifically request the pipeline to provide them with a copy.[15] The submissions should enable these parties to identify the contracts which affect their interests and to determine whether the language of a particular contract is consistent with the parties' assertion that the contract authorizes escalation to the NGPA maximum lawful price.

Protests may be filed before August 15, 1979, by pipelines and before October 15, 1979, by third parties (i.e., persons not a party to the contract).[16] All protest will be noticed in the **Federal Register** and will be forwarded to the Chief Administrative Law Judge for assignment to an Administrative Law Judge for review. The Commission is vesting in the Chief Administrative Law Judge authority to set proceedings for hearing and to issue such procedural orders as may be necessary to expeditiously consider the large volume of protests which may arise under Order No. 23.[17] The Commission anticipates that the Chief Administrative Law Judge will group protests and deal with them on a pipeline-by-pipeline basis unless he finds another procedure is more efficient. Under this procedure protests to contracts containing substantially identical area rate clauses can be handled generically by an Administrative Law Judge, if deemed appropriate.

Protests will be preliminarily reviewed by an Administrative Law Judge to determine if a hearing is necessary. Hearings will be initiated pursuant to 18 CFR 154. 94(i)(4) whenever the Chief Administrative Law Judge (or, if a procedural order of the Chief Administrative Law Judge so provides, the Administrative Law Judge to whom the protest is assigned) determines a hearing is necessary.

Each protest, whether by a third party or by the first sale purchaser, shall include the text to the contractual provisions which the protestor believes is inconsistent with a conclusion that the gas purchase contract authorizes the collection of the higher rate for which a filing has been made. Additionally, the protest may include any other evidence relied upon by the protestor to support his position of lack of contractual authority.[18]

The rule provides that the Chief Administrative Law Judge (or, if a procedural order of the Chief Administrative Law Judge so provides, the Administrative Law Judge to whom the protest is assigned) may summarily dispose of a protest. The rule does not specify the grounds on which summary disposititon can be made; summary disposition must be left initially to the judgment of the Administrative Law Judge, and ultimately to the judgment of the Commission, upon review of the

best copy available

Administrative Law Judge's initial decision. However, the Commission will provide the following guidelines for summary dispositions of third party protests where the parties to the contract agree that contractual authorization exists. Section 270.205(a)(2) provides that contractual provisions similar to the area rate clause permitted by § 154.93(b-1) *"generally"* will be considered contractual authorization to collect an NGPA rate to the extent the parties intended to authorize collection of NGPA rates under the contract. Where the parties state that their intent was to authorize collection of the rates, "considerable weight" will be given to their interpretation.[19] However, the Commission cannot allow the parties' interpretation to be dispositive where that interpretation does not appear to be reasonable in light of the language of the contract and the conduct of the parties. Therefore, the Commission will permit third parties to utilize the protest procedure to present evidence of lack of contractual authorization. However, in such circumstances, the burden of going forward with evidence of lack of contractual authorization is appropriately placed on the third party protestor. Unless the third party protestor can show that the language of the contract is inconsistent with the parties' interpretation, or can include in his protest (or in a supplemental filing) evidence sufficient to show lack of contractual authorization, there is no basis for finding that the parties' conclusion is unreasonable, and the protest should be summarily dismissed.

If the protest is not summarily dismissed, it will be set for hearing. Any interested party, including the first seller, may intervene in a hearing. At the hearing, the burden of persuasion will be on the parties to the contract to establish their position by a preponderance of the evidence.

For all blanket affidavit and interim or retroactive collection filings made after June 15, 1979, an additional evidentiary submission must be filed with the Commission and interested parties by the pipeline within 60 days of receiving notice of such filings. Pipeline protests likewise must be submitted within 60 days of the filings. Third party protests must be submitted within 120 days of the date of the blanket affidavit or interim or retroactive collection filing. These protests to later filings will be handled similarly to the protests to the pre-June 15, 1979, filings.

If a pipeline contests its seller's contractual right to charge and collect a higher rate due to the passage of the NGPA, that pipeline may pay the higher rate subject to refund, or it may refuse to pay the higher rate until the dispute has been resolved. If a third party protestor challenges that contractual authority, in the face of agreement of the parties, the payment by the pipeline is subject to refund. In these cases, as in any case involving natural gas which is subject to the jurisdiction of the Commission under the NGA, if a rate increase filing is not supported by contractual authority, the rate increase filing is a nullity, and any rate charged under that filing is subject to refund.[20]

IV. Public Procedures and Effective Date

The Commission is making these rules effective as final rules on August 15, 1979. A general right to protest was set forth in Order No. 23, issued March 13, 1979. A Notice of Inquiry requesting suggestions regarding that procedure was promulgated on May 2, 1979. Both the Applications for Rehearing of Order No. 23, and the comments received in response to the Notice of Inquiry, made suggestions as to the appropriate procedure to be implemented. The rules and amendments contained herein were developed in consideration of those suggestions and comments. Accordingly, the Commission finds that further notice and public procedures on these rules is unnecessary and impracticable, and that good cause exists to dispense with additional notice and opportunity for comment.

(Natural Gas Act, as amended, 15 U.S.C. 717, *et seq.*; Department of Energy Organization

Act, 42 U.S.C. 7107 *et seq.*; E.O. 12009; Natural Gas Policy Act of 1978, Pub. L. 95–621.)

In consideration of the foregoing, Part 154 of Subchapter E, Chapter I, Title 18, Code of Federal Regulations, is amended as set forth below.

By the Commission.

Kenneth F. Plumb,
Secretary.

[Footnotes]

[1] 44 FR 16886 (March 20, 1979).

[2] P.L. 95–621, 92 Stat. 3350.

[3] "Area rate clauses" are indefinite price escalator clauses of the character permitted under paragraph (b–1) of 18 CFR 154.93.

[4] Order No. 23, at pages 48–49.

[5] *United Gas Pipe Line Co.* v. *Mobile Gas Service Corp.*, 350 U.S. 332 (1955) and *Federal Power Commission* v. *Sierra Pacific Power Company*, 350 U.S. 348 (1955), stand for the proposition that rate increase filings are ineffective under the NGA unless supported by contractual authority.

Of course, contracts may be amended. Order No. 23–A, issued on June 12, 1978, explicitly recognizes the right of the parties to a natural gas purchase contract to amend that contract to allow it to escalate to the highest permissible price under the NGPA. *See* 18 C.F.R. 270.205(c), as amended.

[6] Order on Rehearing of Order 23, at pages 3 and 4.

[7] Docket No. RM79–4, issued November 17, 1978: 43 FR 55756 (November 29, 1978).

[8] Docket No. RM79–4, issued December 28, 1978: 44 FR 1100 (January 4, 1979).

[9] Docket No. RM79–31, issued March 27, 1979: 44 FR 19387 (April 13, 1979).

[10] The filings were specifically stated *not* to abrogate any contractual right to receive gas at a lower price than the NGPA ceiling rate. See 18 CFR 154.94 (h)(7) and (i)(2).

[11] Order No. 23, at page 52. This procedure is only applicable to rate-increase filings involving natural gas which is subject to the jurisdiction of the Commission under the Natural Gas Act.

[12] The Commission indicated in the Order on Rehearing of Order No. 23, in footnote 4, that the procedural issues raised by the applications for rehearing of Order No. 23 would be considered in determining the appropriate procedure to be implemented. Most of the applications for rehearing simply objected to the protest procedure set forth in Order No. 23. The specific proposals made in the applications for rehearing were repeated in the responses to the Notice of Inquiry.

[13] The Commission contemplates a procedure similar to its practice of requiring prefiled testimony in pipeline and electric rate cases.

[14] This evidence may take many forms. For example, the course of conduct of the parties subsequent to the execution of the contract may evince a modification of its original terms. See *Sam Rayburn Dam Electric Cooperative* v. *FPC*, 515 F. 2d 998, 1007 (D.C. Cir., 1975). cert. den. 426 U.S. 907 (1976).

[15] To the extent that the filing deadline or information required by a submission imposes a hardship on any pipeline, adjustment relief is available under § 1.41 of the Commission's regulations.

[16] Within the constraints imposed by the Commission's limited resources, the Commission expects that Staff will endeavor to examine the pipeline reports and challenge the interpretation ascribed to a particular contract by its parties if that interpretation appears to be inconsistent with the text of the contract or with other information known to Staff. If it appears to Staff that the requisite contractual authority does not exist to support an NGA rate change filing, it may contest the filing and request a hearing before an Administrative Law Judge in the same manner as a third party protestor.

[17] The Commission's Rules of Practice will apply to such procedural orders except to the extent the orders make inapplicable a specific provision of the Rules of Practice. However, § 1.28 of the Rules of Practice, relating to certification of questions to the Commission, is applicable to any procedural order of the Chief Administrative Law Judge under this provision.

[18] Those protests which have already been filed with the Commission should be amended to incorporate these requirements.

[19] Order No. 23, at page 49.

[20] *Shell Oil Company* v. *FPC*, 334 F2d. 1002 (3rd Cir. 1964).

[¶ 30,066]

44 F. R. 38837 (July 3, 1979)

18 CFR Part 287

[Docket No. RM79–10; Order No. 37]

Determination of Powerplant Design Capacity

Issued: June 28, 1979.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) hereby gives notice that it is revising and issuing as a final rule the

regulations covering determination of a powerplant's design capacity. The amendment is adopted in response to comments submitted on the interim rule, issued February 9, 1979.

EFFECTIVE DATE: July 23, 1979.

FOR FURTHER INFORMATION CONTACT:

Teresa Ponder, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8100, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 275-0422, or

B. E. Biggerstaff, Office of Electric Power Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street N.E., Washington, D.C. 20426, (202) 275-4721.

I. Background

Section 103(a)(18)(D) of the Powerplant and Industrial Fuel Use Act of 1978 (Act), Pub. L. No. 95-620, required the Federal Energy Regulatory Commission (Commission) to prescribe by February 9, 1979, rules according to which a powerplant's design capacity could be determined. On December 29, 1978, the Commission issued a proposal and requested comments by January 30, 1979. An interim rule was issued February 9 (44 FR 10367, February 20, 1979). However, since the proposal was not noticed in the Federal Register until January 22, 1979, (44 FR 4500) the Commission extended the comment period to March 19, 1979. This rule is now issued as a final rule.

II. Summary of Comments

In response to the proposal and the interim rule, 39 comments were submitted representing the views of 33 parties. (Several parties submitted comments at more than one stage of the proceeding.)

Scope of Application of Design Capacity

Several commenters expressed concern because "design capacity," as determined under the Commission's rules, has been incorporated into the regulations of the Economic Regulatory Administration of the Department of Energy (ERA) as equivalent to "design capability." It is alleged that, as a result, the determination of design capacity has an effect on calculations concerning reliability of service. Many of the commenters expressed great concern that, because such use of the design capacity determination, design capacity should be determined according to the unit's actual (and net) capabilities rather than its designed capacity.

The Commission is prescribing the rules for determining design capacity solely for the purpose of implementing paragraph (18) of section 103(a) of the Act. Paragraph (18) defines a powerplant's identification as either a peakload, intermediate load, or base load powerplant, depending on the plant's equivalent full-load hours of operation during the year. This is the quotient of the plant's annual kilowatt-hours of generation divided by its design capacity, in kilowatts. If the figure does not exceed 1500 hours the plant is a peakload powerplant; if the figure exceeds 1500 hours but not 3500 hours, the plant is an intermediate load powerplant; and if the figure exceeds 3500 hours, the plant is a base load powerplant. The Commission has no authority to define or determine the capability of a powerplant and has not contemplated such use of design capacity in promulgating this rule.

Acceptability of Using the Nameplate Rating

In this rule, the determination of design capacity has been keyed to nameplate ratings. The majority of the comments protest the use of nameplate ratings. Most commenters filing before ERA issued its rules complained that the nameplate rating was much lower than actual capacity. Most filing after ERA issued its rules complained that the nameplate rating was much higher than actual capacity. The comments that focused on ERA's use of the design capacity determination did not tend to present arguments that specifically addressed the acceptability of using nameplate ratings for the purposes of paragraph (18) of section 103(a). Those comments that did address the acceptability of using nameplate ratings for the purposes of paragraph (18) of section 103(a) tended to support the use of the nameplate rating, even though other amendments to the interim rule were suggested.

Nameplate rating designates the performance that the manufacturer was willing to guarantee at the time of sale. It reflects not only the design of the unit but the conditions under which the seller and purchaser expected the unit to operate. In other words, the nameplate rating reflects the manufacturer's opinion of the maximum output the unit could produce over the time periods and under the conditions specified by the buyer. While the nameplate rating does not reflect the unit's net dependable capability, it does represent a realistic estimate of the design capacity of the unit.

The Commission feels that the appropriate standard for design capacity is the gross design capacity of the unit, rather than its net dependable capability. As the Commission reads paragraph (18) section 103(a) of the Act, Congress keyed the identification of peakload, intermediate load, and base load powerplants to the unit's equivalent annual kilowatt-hours of operation at its design capacity. Design capacity is a function of the characteristics built into the machine. Actual capability is a function of the machine's design capacity, changes in weather and electrical characteristics of the system, and physical condition of the equipment. The equipment is constantly deteriorating as the result of normal use as well as malfunctions, and being repaired or replaced from time to time. Actual capability changes from year to year, reflecting changing operating conditions rather than changing design capacity. For purposes of determining whether a powerplant is to be identified as a peakload, intermediate load, or base load powerplant, the Commission does not feel that keying design capacity to actual operating conditions is appropriate. Instead it will continue to rely on nameplate ratings.

Modification of the Nameplate Rating

Several comments suggested, and the Commission agrees, that a powerplant's determined design caapacity should be changed if the powerplant is substantially modified. In the interim rule, the Commission requested comments on the procedures which should be adopted for determining a new design capacity. Upon consideration of the fact that the Commission has no authority with respect to the determination of design capacity except to provide the rules for determination, and the fact that nameplate ratings are changed whenever a unit is substantially modified, the Commission has decided that a unit's determined design capacity should be changed whenever its nameplate rating is changed. Because the regulations provide that design capacity be based on nameplate rating no special provisions for modification of design capacity need by added to the regulations to reflect this fact.

Steam-Electric Generating Units

Several comments indicated that electric generating units are rated according to kilovolt-amperes (kva) rather than kilowatts. A kva rating will always be accompanied by a power factor rating. [1] The kilowatt rating of the unit is the product of the unit's kva and power factor rating. If a unit's nameplate rating is not given in kilowatts, the kilowatt rating may be determined by multiplying the nameplate kva rating by the nameplate power factor.

Several comments suggested that the design capacity of electric generating units should be measured either in kva's, or, in kva's presuming unity power factor (which would establish a kilowatt value exactly equal to the kva generated). The Act's identification of a powerplant as peakload, intermediate load and base load is based on the unit's design capacity for generating kilowatts.

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[1] The apparent power (kva) produced by a generator equals the square root of the sum of the square of the real power (kw) and the reactive power (kvar). Diagrammatically, kilowatts equals kva times power factor, where power factor is defined as the cosine of the angle between voltage and current at the generator terminals.

Assuming a unity power factor would produce an unrealistic kilowatt rating. Therefore, the power factor designated on the unit's nameplate shall be used to determine the unit's design capacity in kilowatts.

Combustion Turbine

A few commenters suggested that a combustion turbine should be rated according to its base load rather than its peakload rating. Very few, if any, combustion turbines are operated as base load powerplants since the operating costs of such units are generally much higher than for steam turbine units. The peakload rating shall continue to be the combustion turbine's design capacity.

Several commenters also suggested that a combustion turbine's nameplate rating be adjusted for actual site conditions. Nameplate ratings for combustion turbines are not as tailored to the purchaser's actual operating conditions as other nameplate ratings. Since the turbine's nameplate rating does not represent as accurately as other nameplate ratings the expected performance of the unit, the Commission has been convinced that the rating should be adjusted for the unit's site elevation. However, we choose to continue the presumption of an ambient temperature of 59 degrees Fahrenheit since the International Standards Organization, the National Electric Manufacturer's Association, and the American National Standards Institute have all adopted 59 degrees Fahrenheit as the standard rating temperature.

Combined Cycle Units

Three commenters protested the method of determining design capacity for combined cycle units. Under the interim rule and this rule, the design capacity of a combined cycle unit is determined by summing the base load nameplate rating of the combustion turbine and the maximum generator nameplate rating of the steam turbine. The commenters felt that the design capacity of a combined cycle unit should be limited by other actual operating condition factors, one of which is the boiler capacity for the steam turbine. Again, these commenters were more concerned that design capacity reflect actual net capacity than the purposes of paragraph (18) of section 103(a) of the Act. Therefore the Commission is not persuaded by their arguments that the nameplate rating is inappropriate.

Incorporation of Information Given in FPC Form 12

Several comments pointed out that confusion is created by referring to FPC Form 12 in the rule to determine design capacity. Since design capacity is determined by the appropriate nameplate rating, and references to FPC Form 12 (where such values are reported to the Commission) are unnecessary and could cause problems, the references to the reports in FPC Form 12 have been eliminated. Nevertheless, the information presently reported in FPC Form 12 indicates several nameplate ratings, hence, the design capacity of many powerplants.

III. Summary of the Rule

The design capacity of a steam-electric generating unit is its maximum generator nameplate rating measured in kilowatts. The design capacity of a combustion turbine is its nameplate rating measured in kilowatts, adjusted for peaking service at an ambient temperature of 59 degrees Fahrenheit (15 degrees Celsius) and at the unit's site elevation. The design capacity measured in kilowatts of a combined cycle unit is the sum of its combustion turbine base load rating adjusted for site elevation

and the maximum generator nameplate rating of the steam turbine portion of the unit. The design capacity of an internal combustion engine is the generator's nameplate rating measured in kilowatts.

(Department of Energy Organization Act, 42 U.S.C. 7107 *et seq.*; Powerplant and Industrial Fuel Use Act of 1978, Pub. L. No. 95-620.)

In consideration of the foregoing, the Commission amends Chapter I of Title 18, Code of Federal Regulations, as set forth below, effective July 23, 1979.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,067]

44 F. R. 45922 (August 6, 1979)

18 CFR Part 281

[Docket No. RM79-15; Order No. 29-B]

Amendments to the Final Natural Gas Curtailment Regulation for Implementation of Section 401 of the Natural Gas Policy Act of 1978

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission has extended the dates for filing petitions for Priorities 1 and 2 treatment of natural gas for certain end-users. The amendment to the Final Regulation postpones, for about 2 weeks, the dates by which essential agricultural users, distribution companies, and pipelines must file requests for special treatment of gas supplies dedicated to certain high-priority uses such as essential agricultural or residential uses. The amendment will make it easier for users and suppliers to protect certain gas supplies from possible curtailment.

EFFECTIVE DATE: July 18, 1979. For new filing dates, see text below.

FOR FURTHER INFORMATION CONTACT: MaryJane Reynolds, Federal Energy Regulatory Commission, Office of the General Counsel, Room 8000, 825 N. Capitol St. NE., Washington, D.C. 20426, (202) 275-4283.

Amendments to the Regulation for the Implementation of Section 401 of the Natural Gas Policy Act; Final Rule

Before Commissioners: Charles B. Curtis, Chairman; Matthew Holden, Jr., and George R. Hall.

Issued July 20, 1979.

Background

On May 2, 1979, the Federal Energy Regulatory Commission ("Commission") issued a permanent curtailment rule (44 FR 26855, May 8, 1979) which established a system of high-priority [Priority 1] and essential agricultural [Priority 2] use requirements and integrated them into the curtailment plans of interstate pipelines. This new rule requires the reordering of curtailment priorities by November 1, 1979 and applies this treatment to deliveries of natural gas beginning on that date. The new rule requires considerable data gathering and reporting by end-users, distributors and interstate pipelines. Under § 281.211(b) of the new regulations, essential agricultural users which seek Priority 2 treatment for their agricultural requirements of natural gas are required to file a request for Priority 2 treatment with their direct suppliers. Local distribution companies have two weeks to review and forward these requests to their interstate pipeline suppliers (§ 281.211(c)) and, if the pipeline purchases gas from downstream pipelines, it must request reclassification of its Priority 2 entitlements from its supplier, within two weeks of receiving information from its customers (§ 281.211(d)). Similarly, direct sale customers and local distribution companies must report Priority 1 requirements to their direct suppliers. Interstate pipelines must report Priority 1 entitlements to their upstream suppliers. Under § 281.212, the interstate pipelines must then file draft tariff sheets and an index of entitlements with the Data Verification Committee ("DVC") and distribute these documents to customers. The DVC must then review the tariff sheets, index of requirements, and the back-up data therefor. On October 1, 1979, the interstate pipelines must file new tariff sheets which implement the permanent curtailment plan protecting high priority and essential agricultural users.

On June 15, 1979, the Commission extended for 30 days the deadline for filing requests for Priority 1 and 2 treatment. Order 29–A (44 FR 37499, June 27, 1979). Under the amended rule, essential agricultural users had until July 15, 1979, to request Priority 2 treatment.

On July 10, 1979, the High Plains Gas Consumer Group *et al.* ("HPGC")[1] filed a motion for an extension of time which would postpone for two weeks, until July 31, 1979, the date by which essential agricultural users must file a request for Priority 2 treatment for natural gas to meet their essential agricultural requirements. HPGC alleges that a large number of on-farm users in the Kansas, Oklahoma, and Texas areas are unaware of the July 15 deadline for requesting Priority 2 treatment. A significant factor contributing to the alleged lack of information is that this is the season for peak agricultural activity and harvesting, keeping many farmers in the field 16–18 hours on many days.

The Commission recognizes that the permanent curtailment plan which is extended to give a preference to essential agricultural requirements in the curtailment plans of interstate pipelines is a new plan based upon a new statute. It is possible that there is not yet general familiarity with this plan embodied in the permanent curtailment rule, even though it was first proposed in January of this year. (44 FR 3725, January 18, 1979). Public hearings were held throughout the country, including one in Amarillo, Texas, in March and April. Moreover, the permanent rule requiring the filing of data by essential agricultural users was issued by the Commission on May 2, 1979. (44 FR 26855, May 8, 1979).

Nonetheless, the Commission has determined that the two week extension should be granted—to further assure the broadest possible participation in the Priority 2 requests by essential agricultural users. However, the dates for local distribution companies and interstate pipelines to make their own requests for upgrading because of requests made for Priority 2 treatment by essential agricultural users must also be extended by two weeks to August 15 and 31 respectively, since those requests are dependent upon downstream (end-user) requirements. At this time, the Commission has determined that it will not amend the rule to provide an automatic postponement of the date for the filing of the tariff sheets under the permanent curtailment rule beyond the present October 1, 1979, date prescribed in § 281.204. However, this leaves only one month between the pipeline's receipt of data necessary to prepare the Index of Requirements and the filing of the tariff sheets, and significantly shortens the time allowed the Data Verification Committee for consideration of the draft index of requirements. Accordingly, the Commission will allow for the waiver of the October 1, tariff filing for one month, to November 1, 1979 for any pipeline which notifies the Commission, through the Secretary, that the Data Verification Committee needs additional time for review of the draft sheets. Any pipeline electing to postpone implementation of its permanent curtailment plan for one month until December 1, 1979, must keep its interim plan in effect for the month of November. The Commission believes that each pipeline may best evaluate the advantages of postponement of the permanent curtailment plan for one month against the disadvantages of modifying its curtailment plan after the beginning of the winter heating season.

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[1] HPGC *et al.* includes High Plains Consumer Group, Texas County Irrigation & Water Resources Association of Gyumon, OK, American Agriculture Movement of Oklahoma, with State headquarters in Oklahoma City (AAM), Sherman County Agribusiness Energy Users Association of Stratford, TX, Beaver County Irrigation Association of Beaver, OK, and Cimarron County Irrigation Association of Boise City, OK.

Section-By-Section Analysis

The amendments in this rulemaking advance the filing dates in § 281.211 (a) and (b) by approximately two weeks. Paragraph (a) is changed in clause (i) of subparagraph (1) by extending the filing date from July 15, 1979 to July 31, 1979. Paragraph (a) is changed in clause (i) of subparagraph (2) by extending the filing date from August 15, 1979 to August 31, 1979. Paragraph (b) is changed in clause (i) of subparagraph (1) by extending the filing date for essential agricultural users from July 15, 1979 to July 31, 1979, in subparagraph (2) by extending the filing date for local distribution companies to August 15, 1979, and in subparagraph (3) by extending the date for requesting reclassification of entitlements by interstate pipeline purchasers to August 31, 1979.

Section 281.212 is changed in paragraphs (b) and (c) to provide an additional two weeks until September 14, 1979, for pipelines to serve indices of entitlement and draft tariff sheets.

Section 281.204 is amended to allow that a pipeline may elect to file its proposed tariff sheets on November 1, 1979 with a proposed effective date of December 1, 1979, if the pipeline (by modification of its tariff where appropriate) continues in effect for November 1979 the interim curtailment plan implemented in accordance with Subpart A. The election is executed by written notification of the election to the Secretary of the Commission.

Effective Date

Section 553(d) of the Administrative Procedure Act requires that publication of a rule be made not less than 30 days before its effective date unless *inter alia* a rule relieves a restriction or the agency finds good cause for more expeditious action. The amendments to § 281.211 and § 281.212 are intended to make it possible for essential agricultural users to exercise their rights to priority treatment of certain gas supplies. In order that the intent of Congress that essential agricultural users be protected from curtailment of natural gas is carried out, the Commission believes that the July 15, 1979, deadline must be extended. The Commission finds good cause to make the amendments to Part 281 effective immediately.

(Natural Gas Policy Act of 1978, Pub. L. 95-621. Department of Energy Organization Act, 42 U.S.C. § 7107 *et seq.*; E.O. 12009, 42 FR 46267; Administrative Procedure Act, 5 U.S.C. § 551 *et seq.*)

In consideration of the foregoing, Subpart B, Part 281, Chapter 1, Title 18 of the Code of Federal Regulations is amended as set forth below, effective immediately.

By the Commission. Chairman Curtis voted present.

Kenneth F. Plumb,
Secretary.

[¶ 30,068]

44 F. R. 45449 (August 8, 1979)

18 CFR Parts 1 and 3

[Docket No. RM79-59; Order No. 38]

Chief Accountant, et al., Delegation of Authority; Final Regulation

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is promulgating amendments to §§ 1.1, 1.7 and 3.5. These amendments delegate authority to take action on a variety of matters to the Chief Accountant, the Directors of the Office of Electric Power Regulation, the Office of Pipeline and Producer Regulation, the Office of Enforcement, and the Office of Opinions

and Review. These delegations are an outgrowth of the Delegations of Authority adopted by the Commission on August 14, 1978.

EFFECTIVE DATE: July 23, 1979.

FOR FURTHER INFORMATION CONTACT: Tom Runge, Office of the General Counsel, Federal Energy Regulatory Commission, Room 3327, 825 North Capitol Street, N.E., Washington, D.C. 20426. (202) 275–4955.

Delegation of the Commission's Authority to Various Staff Office Directors: amendments to rules relating to delegations of Commission's authority; Issued July 23, 1979.

A. Background

On October 1, 1977, pursuant to the provisions of the Department of Energy Organization Act, 42 U.S.C. 7107 *et seq.*, (1977) (DOE Act) and Executive Order No. 12009, 42 FR 46267 (September 15, 1977), the Federal Energy Regulatory Commission (the Commission) was established as an independent regulatory commission within the Department of Energy. Many of the functions and regulatory responsibilities of the Federal Power Commisison were transferred to the Commission, while many others were vested in the Secretary of Energy.

The functions transferred to the Commission include those encompassed by section 309 of the Federal Power Act (16 U.S.C. 825h) and section 16 of the Natural Gas Act (15 U.S.C. 717o), which provide that the Federal Power Commission "shall have power to perform any and all acts and to prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of this Act."

On August 14, 1978, the Commission adopted Delegations of Authority (Phase I), 43 FR 36433, which serve to transfer over 7,000 decisions annually of a largely ministerial nature downward within the Commission, in order to free the Commission's time for issues of greater significance. Shortly thereafter, the Commission undertook to determine whether additional delegations of authority would be beneficial.

The results of these efforts by the Commission are embodied in the new, "Phase II" Delegations of Authority set forth below.

Like the Phase I Delegations, the Phase II Delegations were prompted by the Commission's determination that an inordinate amount of time is spent on matters that can be fairly characterized as routine. While recognizing the importance of all items of business that come to the Commission for determination, the Commission has decided that by delegating certain routine Commission functions to the various office directors, it will be better able to focus on more complicated and controversial tasks. As President John F. Kennedy once pointed out:

> The reduction of existing delays in our regulatory agencies requires the elimination of needless work at their top levels. . . . Unnecessary and unimportant details occupy far too much of the time and energy of agency members, and prevent full and expeditious consideration of the more important issues. The remedy is a far wider range of delegations to smaller panels of agency members, or to agency employee boards, and to give their decisions and those of the hearing examiners a considerable degree of finality, conserving the full agency membership for issues of true moment." (As quoted in *Administrative Law*, K. C. Davis, West Pub. Co., 1977, pps. 50–51.)

In general, the matters being delegated require limited discretionary decisionmaking on the part of the named office director, and the persons affected by a delegated decision may petition the Commission for a prompt review of a staff decision, in accord with 18 CFR 1.7(d).

B. Summary

1. *General:* The Change in § 1.1(f)(23) provides a uniform definition of "uncontested", to guide the staff in its exercise of delegated authority. Thus, in those instances when these rules expressly provide that the staff may act only "in uncontested cases", or may

take action only on certain "uncontested" matters, a timely and proper petition for or notice of intervention by any non-applicant or other non-party, in opposition to the pending matter, will serve to bring the matter directly before the Commission. In sum, the staff may not act in these instances because the proceedings are contested, as the petition for or notice of intervention in opposition indicates.

Non-parties as well as parties will be entitled to appeal staff determinations to the Commission under § 1.7(d) in the same manner that was formerly available only to parties to the proceedings. This change is made clear by replacing the word "party" with the word "person" in § 1.7(d). Further, any person will have 30 days to seek such review instead of the 15 days currently permitted which is made clear by changing "15 days" to "30 days" in § 1.7(d).

If the Commission does not act on any appeal from a staff determination within 30 days after the filing of such an appeal, then the appeal will be deemed to be denied, as indicated by the amendments to the last sentence of § 1.7(d). Of course, with respect to any parties to that proceeding, such a denial of the appeal will trigger the running of the 30-day period for filing a petition for rehearing in accord with § 1.34 under § 19(a) of the Natural Gas Act, § 313(a) of the Federal Power Act, or any other relevant provision of law.

2. *Chief Accountant:* The revisions to subparagraph (b)(6) of § 3.5 eliminate the "$25 million or less" requirement formerly in clause (v), so that approval may be given to applications for any issuance of securities by competitive bidding procedures, whether or not the total value of such securities exceeds $25,000,000. New clause (vi) delegates authority to approve applications for issuance of securities by negotiated placement, of $15,000,000 or less. Finally, new clause (vii) delegates authority to the Chief Accountant—to the extent the company does not disagree—to pass upon actual, legitimate, and original cost, depreciation thereon, and net investment including revisions, and to sign audit reports.

3. *Office of Pipeline and Producer Regulations:* Under revised § 3.5(f), there is delegated to the Director of the Office of Pipeline and Producer Regulation the authority to issue temporary certificates in all uncontested natural gas pipeline cases arising under the Natural Gas Act, and to issue permanent certificates or to amend certificates where the construction cost does not exceed $1,000,000, or where there will be a gas-for-gas exchange. In uncontested cases, the Director is also authorized to amend certificates to conform them with the actual construction. The Director is further empowered in uncontested cases to permit and approve abandonments of facilities and services where the customers agree to the abandonments. The regulations adopted herein also allow the Director to accept tariff and rate schedule filings, except major pipeline rate increases under section 4(e) of the Natural Gas Act. Finally, in certain instances, the Director is authorized to accept compliance filings, pass upon requests for extensions of time, request deficiency materials, and exercise limited waiver authority.

The phrase "by natural gas companies", as formerly used in subparagraph (f)(7), has been deleted, and the phrase "natural gas" has been inserted before the word "applications," to clarify that the staff may pass upon requests to withdraw applications, whether submitted by natural gas companies, by intrastate pipelines, by local distribution companies, by end users, or others who may seek to withdraw such an application.

4. *Office of Electric Power Regulation:* The amendments to § 3.5(g) include additions and modifications to the current delegation rules concerning preliminary permits and licenses for water power projects, and other water resources matters. New subparagraph (g)(3) consolidates and expands former subparagraph (g)(3) and the former, now-deleted subparagraph (g)(10), giving the Director of the Office of Electric

Power Regulation authority to act on studies, plans, reports, maps, drawings, specifications, and new or revised exhibits related to permits or licenses, if the filings are unopposed.

New subparagraph (g)(26) gives the Director authority to act on uncontested headwaters benefits settlements among non-Federal parties, and also to act on the following kinds of uncontested applications, when no environmental impact statement is required: minor or major project licenses; surrenders or amendments of licenses; and changes in the use of licensed project lands or waters or in a project's boundaries. New subparagraph (g)(26) thus subsumes the matters covered by former subparagraphs (g)(4) and (g)(5), which are now both deleted.

Under subparagraph (g)(27), the Director may dismiss or approve withdrawal of license applications when no party contends that licensing is required and the Director determines that licensing is not required. Subparagraph (g)(28) covers the Director's authority to handle correspondence related to preliminary permit and license applications, license amendments, requirements for licensing of electric transmission lines, power site lands, and similar general correspondence. Under subparagraph (g)(29), the Commission makes clear that the Director may require licensees to repair project works and to take related actions to maintain the safety and adequacy of those works. Finally, subparagraphs (g)(30) through (g)(32) deal with certain authority of the Director related to payment of annual charges and allocations of costs for federal multiple-purpose reservoirs.

Subparagraphs (g)(11) and (g)(12) have been amended by replacing their former references to "no opposition" and "adverse intervention" with the adjective "uncontested". Similar conforming changes are made in subparagraphs (g)(20) and (g)(21).

New subparagraph (g)(22) grants authority to approve certain property transfers, consolidations, and acquisitions; power to accept for filing certain agreements, contracts, and schedules, if they are in compliance with prior Commission orders, is conferred in new subparagraph (g)(23). Subparagraph (g)(24) and (g)(25) cover routine posting and filing permission, and routine redesignation authority. Delegated authority to refund or require additional filing fees is set forth in new subparagraph (g)(34). Additional powers to accept, for filing, certain uncontested or previously-accepted rate increases are delegated in subparagraphs (g)(35) and (g)(36).

5. *Office of Enforcement.* Under new § 3.5(h), the Director of the Office of Enforcement is delegated certain authority of a ministerial nature, generally designed to facilitate investigations and relieve the Commission from matters which are basically administrative in nature. The proposed delegations are closely modeled after similar delegations of investigational power to the Staff of the Securities and Exchange Commission, *see* 17 CFR 200.30–4. Included are the powers to designate investigating officers; to deny or permit witnesses in investigations to procure a transcript of their own testimony; to terminate informal non-public investigations; and to terminate the authority of designated investigating officers.

6. *Office of Opinions and Review:* Under new § 3.5(i), the Director of the Office of Opinions and Review may designate "presiding officers" to preside over § 1.38 proceedings (governing reviews by the Commission under § 503(c) of the DOE Act, of contested remedial orders for alleged violations of the Emergency Petroleum Allocation Act of 1973, issued by the Secretary of the Department of Energy), and to preside over § 1.40 proceedings (governing reviews by the Commission under § 504(b) of the DOE Act, of denials by the Secretary of the Department of Energy of adjustment requests based upon special hardship, inequity or unfair burdens).

C. Effective Date

The Commission makes these regulations effective immediately. The regulations concern agency procedure and practice. Accordingly, pursuant to 5 U.S.C. § 553(b), public notice and comments are not required, and, pursuant to 5 U.S.C. 553(d), the regulations may be promulgated effective immediately. The Commission nevertheless invites interested members of the public to submit comments or suggestions regarding these regulations. The Commission and its staff will evaluate any information received from interested persons and will consider appropriate revisions to these regulations as a result of comments received. An original and 14 copies should be filed by August 24, 1979, with the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. All comments should refer, on the cover page, to Docket No. RM79-59.

(Federal Power Act, as amended, 16 U.S.C. 792 *et seq.*, Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.*, Department of Energy Organization Act, 42 U.S.C. 7107 *et seq.*, Natural Gas Policy Act, Pub. L. 95-621)

For reasons stated herein, Parts 1 and 3 of Subchapter A of Chapter I, Title 18, Code of Federal Regulations, are amended as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,069]

44 F. R. 45453 (August 8, 1979)

18 CFR Parts 1 and 35

[Docket No. RM79-61; Order No. 39]

Amendments to the Notice Requirements of the Federal Power Act

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: On January 2, 1979, the Commission amended its regulations under the Federal Power Act to require that changes in existing rate schedules and initial rate schedules be filed not less than sixty days nor more than one hundred-twenty days before the change is to become effective. The change was required by the Public Utility Regulatory Policy Act of 1978 (PURPA). The Commission has found it necessary to make further amendments to related provisions of its rate schedule regulations in order that they also might conform to the changes mandated by section 207(a) of PURPA.

EFFECTIVE DATE: August 2, 1979.

FOR FURTHER INFORMATION CONTACT: Teresa Ponder, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8100, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 275-0422.

Amendments to the notice requirements of the Federal Power Act; issued August 2, 1979.

Background

The Federal Energy Regulatory Commission advises that and is amending § 1.7, relating to petitions for the issuance, amendment, waiver or repeal of rules; § 35.2, relating to the filing of rate schedules; § 35.15, relating to filing of notices of cancellation or termination of rate schedules; and § 35.22, relating to research and development clauses in rate schedules for electric utilities.

Section 207(a) of the Public Utilities Regulatory Policies Act of 1978 (PURPA), Pub. L. No. 95-617, amended section 205(d) of the Federal Power Act (FPA) (16 USC 824(d)) by replacing the word "thirty", whenever it appears, with the word "sixty". As amended, section 205(d) of the FPA reads:

> (d) Unless the Commission otherwise orders, no change shall be made by any public utility in any such rates, charges,

classification, or service, or in any rule, regulation, or contract relating thereto, except after sixty days' notice to the Commission and to the public. Such notice shall be given by filing with the Commission and keeping open for public inspection new schedules stating plainly the change or changes to be made in the schedule or schedules then in force and the time when the change or changes will go into effect. The Commission, for good cause shown, may allow changes to take effect without requiring the sixty days' notice herein provided for by an order specifying the changes so to be made and the time when they shall take effect and the manner in which they shall be filed and published. [49 Stat. 851–852; 16 USC 824(d)]

On January 2, 1979, the Commission issued several amendments to its rate schedule regulations in order to conform filing date provisions to the changes in section 205(d) of the FPA mandated by PURPA. (44 Fed. Reg. 16371, March 19, 1979.) The Commission is now amending additional sections to conform references to filing date requirements to the amended section 205(d) of the FPA.

First, at § 1.7(b), the reference to the "thirty-day notice period provided in * * * section 205(d) of the Federal Power Act" is amended to reflect a sixty-day notice period requirement. Second, at § 35.2(e), a rate schedule will become effective as a result of the amendment sixty rather than thirty days after it is filed and posted with the Commission. This amendment is being made merely to coordinate the definition of effective date in § 35.2(e) with the January amendments to § 35.3 concerning notice provisions for rate schedule filings.

Third, the amendment to § 35.15 changes the time by which a party is required to notify the Commission of a proposed cancellation or termination of a rate schedule. Under the former rule, when a rate schedule or part thereof was proposed to be cancelled or was to terminate on its own terms and no new rate schedule or part thereof was to be filed in its place, each party required to file the schedule had to notify the Commission of the proposed cancellation or termination at least thirty but not more than ninety days prior to the date such cancellation or termination was proposed to take place. As amended, § 35.15 requires each party to notify the Commission of a rate schedule cancellation or termination at least sixty but not more than one hundred-twenty days before the proposed date of cancellation or termination. Finally, at § 35.22(e)(5), a reference to the notice requirements of § 35.3 will be amended to reflect the sixty-day rather than the thirty-day filing requirement.

Effective Date

The Commission issues this final rule effective immediately. The rule merely amends rate schedule filing requirements to conform them to the change mandated by PURPA, and is strictly procedural in nature. If a rule is procedural, section 553 of the Administrative Procedure Act (5 USC § 553) does not require prior notice and opportunity to comment, or publication thirty days before the effective date of the rule.

(Federal Power Act, as amended (16 USC 284(d)); Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95–617; Department of Energy Organization Act, 42 USC 7101, *et seq.*; E.O. 12009, 42 FR 46267.)

In consideration of the foregoing, the Commission amends Parts 1 and 35, Chapter I of Title 18, Code of Federal Regulations as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,070]

44 F. R. 46454 (August 8, 1979)

18 CFR Part 277

[Docket No. RM79-8; Order No. 4]

Regulations of Natural Gas Sales Under the Natural Gas Policy Act of 1978; High Cost Natural Gas or New

Natural Gas Produced From Any Reservoir on the Outer Continental Shelf

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is promulgating § 277.101 as a final rule. The regulation implements section 315(a)(3) of the NGPA and applies to any new contract for the sale of high cost natural gas or new natural gas produced from any reservoir on the Outer Continental Shelf. Section 277.101 prescribes the minimum duration of a new contract for the first sale of high cost natural gas or new natural gas produced from any reservoir on the Outer Continental Shelf (OCS).

EFFECTIVE DATE: August 2, 1979.

FOR FURTHER INFORMATION CONTACT: Clarence Burris, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8106, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 275-0422.

Final rule prescribing 15-year minimum duration for new contracts for some sales of certain OCS gas; Issued August 2, 1979.

Background

The Commission advises that it is issuing as a final rule, § 277.101, which implements section 315(a)(3) of the Natural Gas Policy Act of 1978, Pub. L. No. 95-621 (NGPA).

On December 4, 1978, the Commission issued, in Docket No. RM79-8, interim regulations implementing section 315(a)(3) of the NGPA (43 FR 57597, December 8,1978). These interim regulations became effective as of December 1, 1978. Since the issuance of the interim regulations, the Commission has held numerous public hearings and provided opportunity for written comments on regulations promulgated under the NGPA as required by section 502(b). No comments were received on Part 277. The Commission adheres to its statements in the preamble to this Part but finds that some ambiguity exists in the wording of § 277.101 which will be amended to track the statute more closely. This amendment does not represent a change in Commission policy regarding this section.

Section 277.101 prescribes the minimum duration of a new contract for the first sale of high cost natural gas or new natural gas produced from any reservoir on the Outer Continental Shelf (OCS). A "new contract" is one which is executed on or after December 1, 1978. The regulation defines "high cost natural gas" and "new natural gas" produced from an OCS reservoir and requires that the contract for such first sales shall be for a duration of not less than 15 years or, if less, the commercially producible life of the reservoir.

Public Procedures and Effective Date

The Commission has held numerous hearings on the interim regulations implementing the NGPA Docket No. RM79-3 (43 FR 56448). Comments on Docket No. RM79-8 were to be included in the oral presentations at these hearings. By this process the Commission has complied with the provisions of section 502(b) of the NGPA, which requires that "[t]o the maximum extent practicable," an opportunity for the oral presentation of data, views, and arguments be afforded for certain regulations under the NGPA.

Although opportunity for comment was provided, the Commission has not received any comments on Part 277 during the notice, comment, and hearing process. Thus, the Commission finds that further notice and public procedure with respect to these rules is unnecessary. Because no modification is being made in the substance of Part 277, it will be issued as a final regulation effective immediately.

(Natural Gas Policy Act of 1978, Pub. L. No. 95-621, 92 Stat. 3350; Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.*; E. O. 12009, 42 FR 46267.)

In consideration of the foregoing, Part 277, Subchapter H, Chapter I of Title 18, Code of Federal Regulations, issued as interim regulations on December 4, 1978, is issued as a final rule as set forth below, effective on the date of issuance of this rule.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,071]

44 F. R. 46455 (August 8, 1979)

18 CFR Part 294

[Docket No. RM79-52]

Interim Procedures for Shortages of Electric Energy and Capacity Under the Public Utility Regulatory Policies Act of 1978; Amendment of Interim Rule.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Amendment of Interim Rule

SUMMARY: The Federal Energy Regulatory Commission is amending the interim rule issued on June 15, 1979, implementing Section 206 of PURPA, which added a new Section 202(g) to the Federal Power Act. The interim rule requires public utilities to file with the Commission a summary of procedures to be used in the event of a shortage of electric energy or capacity. The amendment requires that each utility file such a summary, whether or not it anticipates shortages of electric energy or capacity.

EFFECTIVE DATE: August 1, 1979.

FOR FURTHER INFORMATION CONTACT: Adam Wenner, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8104-C, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 275-0422.

Issued August 1, 1979.

On June 15, 1979 the Commission promulgated § 294.101 of its Rules and Regulations[1] in partial fulfillment of the requirements contained in section 206 of the Public Utility Regulatory Policies Act of 1978 (PURPA). Section 294.101(b) of those regulations requires each public utility now serving firm power wholesale customers to submit, by June 29, 1979, a "brief statement describing how it would accommodate any shortage of energy or capacity anticipated to occur prior to September 30, 1979 and which would be likely to affect its firm power wholesale customers."

Several utilities have contacted the Commission seeking to determine whether the requirement to submit such a statement applies if a utility does not anticipate that any shortages will occur during this period.

The Commission's intent in issuing paragraph (b) was to require each utility serving firm power wholesale customers to provide information regarding that utility's plans to accommodate shortages of energy or capacity, whether or not the utility anticipated that shortages might actually occur. Accordingly, we shall amend the interim regulation to eliminate this ambiguity. In order to provide for the filing of these statements by utilities which have not previously done so, we shall further amend the paragraph in order to extend the time for their submission to July 23, 1979.

(Public Utility Regulatory Policies Act of 1978, Pub. L. 95-617, 92 Stat. 3117; Federal Power Act, 16 USC § 792 *et seq;* Department of Energy Organization Act, 42 USC § 7107 *et seq;* E.O. 12009, 42 FR 46267; Administrative Procedure Act, 5 USC § 553).

In consideration of the foregoing, Part 294 of Subchapter K, Chapter I, Title 18 of the Code of Federal Regulations is amended as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,

Secretary.

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[1] 44 FR 37500 (June 27, 1979).

[¶ 30,072]

44 F. R. 48171 (August 17, 1979)

18 CFR Part 1

[Docket No. RM79-65]

Interim Regulation Establishing Procedures for Seeking Interpretations and Declaratory Orders Under the Natural Gas Policy Act of 1978

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Interim Regulations; and request for comments.

SUMMARY: Section 502(c) of the Natural Gas Policy Act of 1978 (NGPA) requires the Federal Energy Regulatory Commission (Commission) to prescribe procedures for seeking interpretation under the NGPA. The Commission promulgates interim regulations setting forth procedures whereby any person may seek interpretations of the NGPA as well as rules and orders issued thereunder. The interim rules provide that such an interpretation is issued by the General Counsel and may be relied upon only by the person to whom it is issued. The interim rules also provide procedures for seeking Declaratory Orders and interpretative rules from the Commission concerning the NGPA. The effect of these rules is to make clear both the procedures for applying for interpretations and the effect of an interpretation.

DATES: *Effective date:* August 7, 1979; deadline for comments September 12, 1979; hearing September 12, 1979.

ADDRESS: Send comments to Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Mary Jane Reynolds, (202) 275-4283.

August 7, 1979.

A. Background

In order to implement its responsibility under section 502(c) of the Natural Gas Policy Act of 1978 (NGPA), the Federal Energy Regulatory Commission (Commission), is promulgating Interim Regulations providing procedures so that persons may seek an interpretation pertaining to the NGPA or any rule or order issued thereunder. The Commission is also promulgating procedures whereby persons may seek interpretative rules pertaining to the NGPA or any rule or order issued thereunder by the Commission. Section 502(c) of the NGPA requires the Commission to establish by rule "* * * procedures which are available to any person for the purpose of seeking an interpretation." As will be discussed below, the rules are issued on an interim basis so that persons interested in seeking an interpretation from the General Counsel of the Commission may do so immediately.

B. Summary of the Commission's Interim Regulations

The interim rule establishes a new § 1.42 in the Commission's rules of practice and procedure (18 C.F.R. 1.42) in order to provide procedures whereby persons may seek written interpretations from the General Counsel construing the NGPA, or rules or orders issued thereunder by the Commission. Procedures also are established for publication of interpretative rules that will have general applicability and effect.

Interpretations will be issued based on certain facts relating to either completed or prospective acts or transactions. If an interpretation is sought based on prospective acts or transactions, the planned act or transaction must be sufficiently developed so that the likelihood of its occurrence can be demonstrated. Interpretations will not be made in cases where the facts, acts or transactions are hypothetical. The

Commission believes that Staff time and effort is more efficiently utilized by dealing with facts, acts, or transactions that will in all likelihood occur or have occurred.

Section 1.42(d) establishes the necessary contents of a request for an interpretation. A full and complete statement of the facts pertaining to the act or transaction is required. If the request for an interpretation describes an act or transaction which is part of a larger integrated act or transaction, information pertaining to the entire transaction must be submitted.

A request for an interpretation must also indicate for which statutory section, rule or order an interpretation is sought, and must state the precise question which the applicant wishes answered. The regulations provide that the applicant may set forth a proposed answer, in which case the request must also set forth the legal basis for the proposed answer and the legal and business consequences which will flow from the transaction.

A request made to the General Counsel for an interpretation must be accompanied by a statement that to the best of the applicant's information, knowledge and belief, there is no untrue statement of a material or relevant fact, and that there was no omission of a material or relevant fact. Section 1001 of Title 18 of the United States Code is applicable to the factual statements presented in request for interpretations.

The regulations also provide that a person requesting an interpretation specify in the request each person who is a direct participant in the act, transaction or circumstance. Likewise each direct participant must be notified of the request and be provided a copy of it. If the direct participant disagrees as to the accuracy of a relevant or material fact, he may so inform the Office of the General Counsel.

Paragraph (e) provides that the General Counsel may request additional information in connection with any interpretation request. Paragraph (f) indicates that information submitted in a request for an interpretation may be used by the Commission or Commission Staff in their official capacities. Accordingly, information provided can be used in an investigation.

Paragraph (g)(1) states that any interpretation made by the General Counsel shall be in writing. The General Counsel may determine not to issue an interpretation, in which case the person who requested the interpretation and direct participants to the act or transaction shall be notified in writing of such decision and the reason for it. (§ 1.42(g)(2))

Paragraph (g)(3) provides that only persons to whom an interpretation is specifically addressed, and other persons who are named in the request, who are direct participants in the transaction and who are aware of the pendency of the request, may rely upon the interpretation. The purpose of the provision is to insure that requests for interpretations be limited to specific acts or transactions. Interpretations, generally, have no precedential value, and should not be cited as such in Commission proceedings or in other applications for interpretations. No reliance by anyone on an interpretation is permitted if the request for interpretation omitted or misrepresented a material fact, or if a material fact has changed after an interpretation is issued. If the action taken by persons directly involved in the acts or transactions differs from the facts presented, likewise, no reliance on an interpretation is permitted.

The Commission also wishes to note that it had established a procedure whereby persons could telephonically contact the Commission staff regarding questions about certain NGPA provisions and the regulations issued thereunder. Callers were informed at the time the telephonic contact occurred that an oral answer could be relied upon only if the interpretation was confirmed in writing.[1] Indeed the Commission so stated in a press release issued on November 1, 1978, by the Commission's Office of Public Information. We wish to make clear again that no caller may rely on oral advice provided either in the past or in the future unless confirmed in writing. If persons need advice upon which they can rely with certain limitations, the procedures in this rule should be utilized.

Section 1.42(g)(4) states that an interpretation may be rescinded or modified prospectively at any time. A rescission or modification may be effected by notifying persons who are entitled to rely on the interpretation of the rescission or modification at the address(es) contained in the original request. Section 1.42(g)(5) provides that an interpretation can only be relief upon to the extent that the applicable NGPA section, or rule or order remains in effect. The Commission is thus placing persons requesting interpretations on notice that if the law, rule or order for which an interpretation has been given changes, the interpretation may no longer be applicable. Moreover, if the rule or the NGPA is amended retroactively, the interpretation may be modified retroactively to the date of the effective amendment or statutory change. The Commission recognizes that in certain limited situations a retroactive application of a regulation may work a special hardship, inequity, or unfair distribution of burdens. In such circumstances, the Commission's procedures for adjustments, 18 CFR 1.41 are applicable enabling persons thus disadvantaged by their reliance on an interpretation to obtain relief.

An interpretation of the General Counsel is binding on Staff; Staff will not recommend to the Commission that it take enforcement action against a person who has acted in reliance upon an interpretation he has received from the General Counsel. However, since the interpretation is not binding upon the Commission, the Commission is of the view that an interpretation does not constitute final agency action within the meaning of the Administrative Procedure Act, 5 U.S.C. 704, and hence is not subject to judicial review. Although not legally binding upon the Commission, which can revoke, modify or rescind the opinion of the General Counsel, it is unlikely that the Commission would seek civil or criminal penalties against a person for past activities undertaken in reliance upon the written interpretation of the General Counsel.

Section 1.43 allows any person to seek a declaratory order from the Commission. However, the Commission in its discretion may place a low priority on the issuing of Declaratory Orders in light of its work load and because of the availability of interpretations from the General Counsel.

There is no appeal from an interpretation of the General Counsel. The reason there is no administrative review of the interpretation lies in the nature of an interpretation and in the statutory basis for the rule. Section 502(c) requires the Commission to promulgate rules for the making of adjustments to rules or orders issued by the Commission under the NGPA as may be necessary to prevent special hardship, inequity or unfair distribution of burdens. Such rule shall include procedures for obtaining interpretations, modifications, rescissions of, exceptions to, or exemptions from such rules or orders. Section 502(c) also requires that appeals from denials of adjustments be provided. The Commission has promulgated such procedures contained in 18 CFR 1.41 wherein requests for adjustments can be made and review from denials of adjustments can be obtained. Those procedures contemplate the grant of specific relief in order to prevent special hardship, inequity or unfair distribution of burdens.

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[1] Callers were specifically instructed that any answer provided was in informal staff interpretation and could not be relied upon as an official interpretation. Callers were notified that an official interpretation could be obtained by filing a request with the General Counsel.

Interpretations do not fit within the nature of such proceedings because an interpretation does not grant or deny relief; rather it is an explanation of how the law or Commission rules or orders affect an actual or contemplated business transaction. An interpretation is thus a legal opinion of the General Counsel clarifying the meaning of the NGPA or a rule or order of the Commission issued thereunder as they may relate to a specific transaction.

The concept in Section 502(c) of a denial of adjustment relief requiring administrative review is thus inappropriate when applied to interpretations, and accordingly, the interim rule provides that no appeal of an interpretation of the General Counsel may be taken to the Commission. As stated above, if a person believes the regulations work a special hardship, inequity, or unfair distribution of burdens, a clarification of the meaning of the regulations should not be requested. An application pursuant to the Commission's adjustment procedures in § 1.41 is the proper course of action wherein the method the regulation works the hardship, inequity or unfair distribution of burdens can be addressed. Likewise, since an interpretation is a legal opinion of the General Counsel and not an order of the Commission it is not a final agency action and therefore judicial review of an interpretation is inappropriate.

As discussed above, the Commission generally will not pass upon an interpretation issued by the General Counsel. However, the Commission upon its own motion or upon the request of any person, may cause to be published in the **Federal Register** an interpretative rule. Interpretative rules have general applicability, and any person is entitled to rely upon them and cite them as precedent. Since an interpretative rule is issued by the Commission and not subject to further Commission review, we realize that the issuance of an interpretative rule may in some circumstances be final agency action from which judicial review may be obtained.

We note that any person may request the Commission to issue an interpretative rule. While applicants may request such treatment, the Commission will not automatically grant it. The Commission intends that interpretative rules will deal with recurring questions, questions which would have a major precedential effect, or other questions which the Commission believes it should address publicly. The request for an interpretative rule should not be made in an attempt to exhaust administrative remedies for ultimate judicial review. If an applicant wishes a Commission interpretation under the NGPA, he may seek a Declaratory Order.

The Commission has decided to make these regulations effective immediately on an interim basis. Since the NGPA is recently enacted legislation which substantially changes the method and manner by which natural gas prices will be established, important questions regarding the NGPA have been raised. In addition, the Commission has promulgated regulations implementing certain parts of the NGPA, and shall continue to promulgate regulations pursuant to the NGPA, which may need clarification. As a result, the Commission believes it necessary to implement these regulations immediately, so that persons in need of an interpretation can obtain one as quickly as possible.

C. Written Comment Procedures

Interested persons are invited to submit written comments, data, views or arguments with respect to this proposal. An original and 14 copies should be filed with the Secretary of the Commission. All comments received prior to September 12, 1979 will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the Commission's public files and will be available for public inspection in the

Commission's Office of Public Information, 825 North Capitol Street, N.E., Washington, D.C., during regular business hours. Comments should be submitted to the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should reference Docket No. RM79-65.

Public Hearing Procedures

A public hearing concerning this proposal will be held in Washington, D.C. on September 12, 1979 beginning at 9:30 a.m. and will continue if necessary on the following day. Any person interested in this proceeding or representing a group or class of persons interested in this proceeding may make a presentation at the hearing provided a written request to participate is received by the Secretary of the Commission prior to 4:30 p.m., on September 4, 1979.

Requests to participate in the hearing should include a reference to Docket No. RM79-65, as well as a concise summary of the proposed oral presentation and a number where the person making the request may be reached by telephone. Prior to the hearing, each person filing a request to participate will be contacted by the presiding officer or his designee for scheduling purposes. At least five copies of the statement shall be submitted to the Secretary of the Commission prior to 4:00 p.m., September 11, 1979. The presiding officer is authorized to limit oral presentation at the public hearing both as to length and as to substance. Persons participating in the public hearing should if possible, bring 10 copies of their testimony to the hearing.

The hearing will not be a judicial or evidentiary-type hearing. There will be no cross-examination of persons presenting statement. However, the panel may question such persons and any interested person may submit questions to the presiding officer to be asked of persons making statements. The presiding officer will determine whether the time limitations permit it to be presented. If time permits, at the conclusion of the initial oral statements, persons who have made oral statements will be given the opportunity to make a rebuttal statement. Any further procedural rules will be announced by the presiding officer at the hearing. A transcript of the hearing will be made available at the Commission's Office of Public Information.

(Natural Gas Policy Act of 1978, Pub. L. No. 95-621; Department of Energy Organization Act, Pub. L. No. 95-91; E.O. 12009, 42 F.R. 46267)

In consideration of the foregoing, Part I, Subchapter A, Chapter I of Title 18, Code of Federal Regulations, is amended as set forth below.

By the Commission.

Lois D. Cashell,
Acting Secretary.

[¶ 30,073]

44 F. R. 48174 (August 17, 1979)

18 CFR Parts 154 and 157

[Docket No. RM79-22]

Amendment and Clarification of the Commission's Interim Regulations Implementing the Natural Gas Policy Act of 1978 and Regulations Under the Natural Gas Act; Order on Rehearing of Order No. 23-B

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Order on Rehearing of Order No. 23-B.

SUMMARY: The Federal Energy Regulatory Commission, in Order No. 23-B, set forth the requirements for pipeline evidenciary submissions and protests involving the interpretation of price escalation provisions in natural gas purchase contracts. The procedure is necessary for the Commission to exercise its statutory review function of rate-increase filings under the Natural Gas Act. The Order on Rehearing of Order No. 23-B amends those procedures in the following ways: (1)

Pipelines must submit, by September 5, 1979, data concerning small producer contracts; (2) producers are required to be joined as parties to any protest; (3) producers may request a copy of the pipeline evidenciary submissions, and may file supplemental information.

DATES: Amendments effective on August 15, 1979.

ADDRESSES: All filings should reference Docket No. RM79-22 and should be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Philip Yates, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 275-4845.

August 6, 1979.

On June 21, 1979, the Federal Energy Regulatory Commission (Commission) issued Order No. 23-B [1] in Docket No. RM79-22. That order established "a general protest procedure in which parties in interest can petition the Commission for a specific determination as to whether a particular contract clause constitutes the requisite authority to charge and collect Natural Gas Policy Act rates." [2]

Fifteen applications for rehearing of Order No. 23-B were timely filed.[3] Several made helpful suggestions which have been adopted.

I. Burden of Proof

Order No. 23-B addressed the proper distribution of the burden of proof in cases involving a third party protest to an assertion of contractual authority by the parties to the contract. That order allocated the initial burden of going forward (also known as the burden of production) upon the third party protestor, to establish that the contract did not constitute such authority. If that burden is satisfied, a hearing will be held; if not, the third party protest will be summarily dismissed. At the hearing, Order No. 23-B set the burden of persuasion upon the parties to the contract; to prevail in their position, the parties must prove by a preponderance of the evidence that the contract does constitute the requisite contractual authority.

Almost every application for rehearing objected to this allocation of the burden of proof. Potential third party protestors, as well as the potential opponents of such protests took similar, mirror-image positions: the full burden should be on the other side. Basic evidence law and the Administrative Procedure Act were cited by both sides in support of their contrary positions.

The Commission will not change this allocation of burdens, but we will further amplify the respective burdens, and attempt to give additional guidance to the Administrative Law Judges in determining whether the third party protestor's burden of production has been met.

As stated in Order No. 23-B, and earlier in Order No. 23, "considerable weight" will be given to the interpretation ascribed to a contract by the parties to the contract. In essence, this statement reflects a presumption that (1) the parties to a natural gas purchase contract should know what their intent was when they executed the contract, and (2) those parties are truthful in an assertion regarding that intent. Thus, when a pipeline and a producer assert in a filing to the Commission that a particular contract authorizes the collection of an NGPA maximum lawful price, the Commission will presume that assertion is accurate.[4] If nothing more is shown, that presumption will stand.

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[1] 44 FR 38834 (July 3, 1979).

[2] Order No. 23 at 52 (44 FR 16895, March 20, 1979). For purposes of this order "assertions of contractual authority" refers to the assertion of the contractual authority to charge and collect a maximum lawful price under the Natural Gas Policy Act of 1978 (NGPA).

[3] See appendix for list of those who submitted applications for rehearing.

However, the presumption may be rebutted by a third party protestor, by coming forward with enough evidence to show that there is not contractual authority to charge and collect the NGPA rate. That showing must involve more than a "scintilla" of evidence; it must be such that a reasonable man could infer that contractual authority does not exist.[5]

If the third party protestor's burden of production is satisfied, a hearing will be held. However, as stated previously, the burden of persuasion will be upon the parties to the contract to establish their position by a preponderance of the evidence.[6] The burden of persuasion is properly placed on the parties to the contract because they have much easier access to the information which is relevant to the issue of contractual intent.

The Commission also should address the burden of proof involving a protest by a party to a natural gas contract. In such a case, the protestor will have no burden of going forward, because there is no presumption to overcome. Further, the burden of proof in such a case will be entirely on the party seeking the rate increase.

One application for rehearing requested that Order No. 23–B should provide for the summary grant of a protest. The Commission believes there cannot be a summary granting of a third party protest in the face of the parties' assertion of the existence of contractual authority to charge and collect NGPA rates. In such a case, even if the contract on its face apparently will not support an assertion of contractual authority, that contract must be interpreted in light of the commercial context of the contract; the parties must have an opportunity to establish that context.

II. Evidentiary Submissions

Several comments addressed the evidentiary filings required to be made by interstate pipelines. The most obvious defect in the requirement was noted by Transcontinental Gas Pipeline Corporation: Order 23–B limited the required evidentiary submissions by interstate pipelines to those contracts for which a blanket affidavit was filed or for which an interim or retroactive collection filing was made. *See* § 154.94(h) and Part 273 of the Commission's regulations. This limitation left out small producer contracts, because small producers do not necessarily make such filings.

There is no basis for treating small producer contracts differently than other contracts for purposes of determining whether there is contractual authority to charge and collect a maximum lawful price set by the NGPA. Accordingly, the Commission has amended the small producer regulations in § 157.40 to allow a protest to be made to an assertion by a small producer that the requisite contractual authority exists. Conforming amendments have been made in § 154.94(j) to include reference to these protests. However, the pipelines will not be required to submit the information regarding small producers until September 5, 1979. *See* § 154.94(j)(2)(i).

Several other defects were pointed out by other parties. The rules will be amended to include the following changes:

(1) Producers will be allowed, in § 154.94(j)(2)(i), to request a copy of an evidentiary submission that relates to that producer, and to request from the pipeline a list of the parties served with a copy of the evidentiary filing.

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[4] Associated Gas Distributors requested that the pipeline evidentiary filings be made under oath. This will not be required. The penalties for false filings contained in 18 U.S.C. 1001 apply to such filings whether or not the filing is made under oath.

[5] *See* McCormick on Evidence, 2nd Ed. at page 789.

[6] The Commission's view of presumptions is consistent with Section 301 of the Federal Rules of Evidence.

(2) Producers will be allowed, in § 154.94(j)(2)(ii), to file additions to the evidentiary filings submitted by the pipeline.

(3) Pipelines will not be required to resubmit information that has previously been filed in a prior evidentiary submission. If, for example, a new well is the subject of an interim collection filing, and the information is contained in a prior evidentiary submission, the pipeline will satisfy the requirements of § 154.94(j)(1) by simply refering to the prior filing. *See* § 154.94(j)(1)(vi).

No other changes will be made in the required evidentiary filings. If additional information is required by a third party protestor, access to the entire contract is available both in the Commission's files and in the public files of each natural gas company. *See* § 154.1 of the Commission's regulations. The present filing requirements will supply potential protestors the opportunity to identify and protest those contracts in which they may have an interest.

III. Protests

Several producer comments focused on the issue of adequate notice of a protest to the parties to the contract. As correctly pointed out by the Indicated Producers, Order No. 23–B is defective because it does not provide specific notice to the parties to the natural gas purchase contract. Accordingly, § 154.94 (h)(8) and (i)(3) have been amended to include a requirement that a protest be served with the producer, in the case of a protest by the purchaser, and on both the producer and purchaser, in the case of a third party protest.

Several applications for rehearing indicated a strong belief that producers should be *required* to be joined as parties in a case resulting from a third party protest, rather than be *allowed* to intervene. The Commission agrees, since the issues raised by a protest always will involve the rights of the producer, and any order by the Commission as a result of a protest would effect those rights. Consequently, § 154.94(j)(4)(ii) has been amended to reflect this view.

The Commission disagrees with the suggestion that the regulations should limit who can file a protest. The Commission believes that the public interest is not served by attempting to limit the class of persons who may protest an assertion of contractual authorization. If a "standing" requirement were imposed, substantial resources of the protestor, producer, purchaser and the Commission would have to be expended in determining that issue, rather than the more fundamental question of the existence contractual authority. For these reasons, the Commission will not impose limitations upon who may file a protest.[7]

However, the Commission wishes to make it clear that protests must specifically identify the contract which it addresses. Further, the protestor must state the reasons why he believes that any particular contract is inconsistent with the conclusion that it constitutes contractual authority to charge and collect the NGPA rate. Thus, "blanket protests" which apply to all natural gas purchase contracts will be summarily dismissed as not having met the burden of production. *See* § 154.94(j)(3).

The Commission also wishes to clarify, pursuant to the request of the New York Public Service Commission, the meaning of the words "supplemental filing" on page 16 of Order 23–B. The Commission intends that a protest may be supplemented by additional information, if the additional information is submitted before the protest is resolved by summary dismissal or before the hearing.

IV. Jurisdiction under the Natural Gas Act

Several of the parties filing applications for rehearing objected to the Commission's position, taken in the Order on Rehearing of Order No. 23, issued May 11, 1979, that the Commission would interpret only contracts involving natural gas which was subject to the jurisdiction of the Commission under the Natural Gas Act ("NGA gas"). Shell Oil Company, on the other hand, objected to allowing protests to be filed to interim collections involving "NGA gas" which will become "non-NGA gas" as soon as a final determination is made that the gas falls within one of the categories governed by NGPA section 601(a)(1)(B), (as soon as such a determination becomes final, the "NGA gas" becomes "non-NGA gas").

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[7] Staff also may file protests; staff protests will be treated the same as other third party protests.

The Commission will adhere to its previously stated position: "NGA gas" contracts are within the scope of the Commission's duty to ascertain whether contractual authority exists for a rate increase. There is no such duty for "non-NGA gas." And specifically addressing Shell Oil's concern, even if "NGA gas" will soon become "non-NGA gas," the duty continues *until* the gas becomes "non-NGA gas." Thus, protests concerning the gas covered by NGPA section 601(a)(1)(B) will be considered but the Commission's interpretation will govern only those deliveries made before the determination becomes final.

The Commission orders: Except to the extent previously discussed, the applications for rehearing of Order 23–B are denied.

This order on rehearing amends the rules set forth in Order 23–B which will become effective as final rules on August 15, 1979. In Order 23–B the Commission found that further notice and public procedures on the rules promulgated in Order 23–B was unnecessary and impracticable, and that good cause existed to dispense with additional notice and opportunity for comment. For the same reasons as were articulated in Order No. 23–B, the Commission makes the same finding with respect to this order on rehearing.

(Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.;* Department of Energy Organization Act, 42 U.S.C. 7107, *et seq.;* E.O. 12009, 42 FR 46267; Natural Gas Policy Act of 1978, Pub. L. 95–621)

In consideration of the foregoing, Parts 154 and 157 of Subchapter E, Chapter I, Title 18, Code of Federal Regulations, are amended as set forth below. The changes in the rules contained herein are procedural, and thus the thirty-day requirement of 5 U.S.C. 553(d) does not apply. In addition, it is necessary, in view of the need to coordinate these changes with the rules promulgated in Order No. 23–B, to make these amendments effective on August 15, 1979.

By the Commission.

Lois D. Cashell,
Acting Secretary.

[¶ 30,074]

44 F. R. 48180 (August 17, 1979)

18 CFR Part 271

[Docket No. RM79-66; Order No. 42]

Ceiling Prices; Final Rule Amending Regulations on New Natural Gas and Certain Natural Gas Produced From the Outer Continental Shelf

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Regulations.

SUMMARY: The Commission is issuing as final regulations Subpart B of Part 271 which implements section 102 of the Natural Gas Policy Act of 1978 (NGPA). The regulations contain several revisions to the interim regulations. Section 102 of the NGPA pertains to new natural gas and certain natural gas produced from the Outer Continental Shelf.

EFFECTIVE DATE: August 14, 1979.

FOR INFORMATION CONTACT:

Elisabeth Pendley, Office of the General Counsel, Federal Energy Regulatory Commission, Room 4016–H, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 275–0515.

Howard Kilchrist, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, Room 6112, 825

North Capitol Street, N.E., Washington, D.C. 20426, (202) 275-0435.
Issued: August 14, 1979.

I. Background

On December 1, 1978, the Federal Energy Regulatory Commission (Commission) issued interim regulations (43 FR 56448, Dec. 1, 1978) implementing the Natural Gas Policy Act of 1978 (NGPA), Pub. L. No. 95-621. Part 271, Subpart B of the interim regulations implements section 102 of the NGPA which applies to the first sale of new natural gas or natural gas produced from a new Outer Continental Shelf (OCS) reservoir under an old OCS lease. The final regulations issued today define terms used in section 102 and establish special rules to implement section 102.

II. Summary of Comments

Sections 271.201 and 271.203 of Subpart B define for what natural gas the price specified in § 271.202 (referencing the price table in § 271.101) may be charged.

Section 102 of the NGPA covers natural gas produced from a new onshore well or new onshore reservoir and from the OCS either under a new OCS lease or under an old OCS lease if produced from a newly discovered OCS reservoir.

A new onshore well must be spudded or increased in depth at least 1,000 feet on or after February 19, 1977, and must be either 2.5 miles from the nearest marker well or have a completion location 1,000 feet deeper than the deepest completion location for any marker well within 2.5 miles. Section 2(5) of the NGPA defines a marker well as any well from which gas was produced in commercial quantities after January 1, 1970, and before April 20, 1977, except a well spudded on or after February 19, 1977.

A new onshore reservoir is one which did not produce gas in commercial quantities before April 20, 1977, and which is not subject to the behind-the-pipe and the withheld gas exclusions.

Natural gas produced from the OCS qualifies for the section 102 price if it is either produced under an OCS lease entered into by the Secretary of the Interior on or after April 20, 1977, or is produced under an old OCS lease from a reservoir which was not discovered before July 27, 1976.

One comment suggested that the definition of "reservoir" in section 2(6) of the NGPA be added to the definitions in § 271.203. Because § 270.102 provides that terms used in Subchapter H shall have the same meaning as they have in the NGPA (absent further definition in the regulations) the suggested modification is unnecessary and will not be adopted.

Another comment suggested that new recompletions, either by plug back or re-entry, should qualify for the section 102 price. Although it is more economical in some instances to recomplete a well than to drill a new well, the statutory language limits the section 102 price, inter alia, to wells spudded on or after February 19, 1977 or wells drilled to an increased depth of at least 1000 feet on or after February 19, 1977. Therefore, new recompletions would qualify for the section 102 price only if re-entry involves drilling to an increased depth of at least 1000 feet and the completion location is located either at a depth of at least 1000 feet below the deepest completion location of each marker well within 2.5 miles of the subject well or 2.5 miles or more from the nearest marker well.

Section 271.204 of the regulations establishes special rules implementing section 102. The majority of the comments received on Subpart B of Part 271 addressed this section.

Section 102(c)(1)(B)(ii) of the NGPA defines as "new natural gas" onshore gas produced from a new well the completion location for which is at least 1,000 feet below the deepest completion location of each marker well within 2.5 miles of the new well. Paragraph (a) of § 271.204 establishes a special rule prescribing the method for measuring this 1,000 foot distance. Several comments complained that requiring this distance to be measured

from the highest perforation point of such marker well completion location to the highest perforation point in the new well completion location

permitted "the producer greater leeway in charging consumers higher prices without justification." The comments suggested that the distance be measured from the highest perforation point in the new well to the "lowest perforation point of such marker well" in order to adhere to the statutory language in section 102(c)(1)(B)(ii) which refers to "any completion location . . . at a depth of at least 1,000 feet *below* the *deepest* completion location of each marker well." [Emphasis added.] The Commission considered such a suggestion prior to issuing its interim regulations and decided to adopt the current rule "for reasons of ease of measurement and consistency." This remains the Commission's point of view. The line of measurement for the 1000 foot distance between completion locations begins with the statutorily designated deepest completion location in the marker well and is drawn to the completion location in the new well. To add consistency to this measurement, the Commission designated the highest perforation point in each completion location as the point of measurement; i.e., the highest perforation point in the deepest marker well completion location and the highest perforation point in the new well completion location. Section 271.204(a) not only upholds the statutory standard but specifically pinpoints the exact measurement point within each completion location. Section 271.204(a) is being revised slightly to clarify the regulations in this regard.

The special rule in paragraph (b) of § 271.204 implements section 102(d) of the NGPA. Section 102(d) states that gas produced under an old OCS lease from a reservoir discovered on or after July 27, 1976, qualifies for the section 102 price. Section 102(d)(2) excludes from the category of qualifying reservoirs those reservoirs which were penetrated before July 27, 1976, and which were either demonstrated by OCS Order No. 4 test results or evidence to be "capable of producing in paying quantities" or demonstrated by certain other analytic methods to be "commercially producible."

The special rule in paragraph (b) of § 271.204 states that a reservoir is "capable of producing in paying quantities" if a well completed on it could reasonably be expected to produce sufficient natural gas to yield revenues in excess of operating costs. One comment suggested that the term "operating costs" be defined as "out of pocket costs." The Commission agrees that the term "operating costs" needs definition. Therefore, a sentence will be added to § 271.204(b) to indicate that: "For purposes of this section, operating costs include those out-of-pocket cash expenses necessary to operate and maintain a well."

The special rule in paragraph (c) of § 271.204 prescribes what OCS reservoirs may qualify under section 102(d) because, although penetrated before July 27, 1976, such reservoirs were shown by certain analytical tests not to be "commercially producible."

The definition of "commercially producible" references the definition in § 270.102(b)(4) for "production in commercial quantities." That term appears in several places in the NGPA and is used in section 102(c) to prescribe what natural gas will qualify under section 102 because produced from an *onshore* reservoir which did not produce in commercial quantities prior to April 20, 1977.

Numerous comments objected to linking the terms "commercially producible" (for OCS reservoirs) and "production in commercial quantities" (for onshore reservoirs). The latter term is defined in § 270.102(b)(4) as production which is either sold and delivered to one other than the operator or which is retained for beneficial economic use. The comments argued for a definition of "commercially producible" similar to the definition for "capable of producing in paying quantities." One comment explained that:

> Any well bore in which gas is found probably could have one Mcf of gas sold from it if appropriated facilities were installed. However, that by no means is determinative of whether a reservoir is "commercially producible."

The Commission dismissed this issue in the preamble to the interim regulations, stating:

> The Commission has found no basis for concluding that the term "commercially producible" has a meaning different from "production in commercial quantities."

The Commission continues to believe that the production test for new onshore and new OCS reservoirs should be the same unless factors such as the applicability of OCS Order No. 4 require a different standard. Use of an economic test employing standards other than those of § 270.102(b)(4) (sale and delivery of the gas or its retention for beneficial economic use) would involve difficult subjective decisions. If a reasonable return standard were considered, it would be applied to costs incurred in 1977. While the available 1977 costs and market prices for natural gas or crude oil produced might be used as a guideline, the subjective analysis of model costs, and model market prices which could have been incurred would place unreasonable administrative burdens on the jurisdictional agencies and on Staff. Because such an in-depth economic test would create such an administrative burden and the test of sale and delivery or retention for beneficial economic use is a reasonable interpretation of the statute, the Commission believes that the current definition of "commercially producible" should be retained.

Several comments addressed the definition of "production in commercial quantities" in § 270.102(b)(4) and the special rule in paragraph (e) of § 271.204 assigning the burden of proof for establishing this factor. Section 270.102(b)(4) states that, except for use in testing and for other field uses, "production in commercial quantities" means production from a reservoir which is either sold and delivered to one other than the operator or retained for beneficial economic use by the operator or any owner of the production at severance. Section 271.204(e)(1) of the regulations tracks the language of section 102(c)(3)(A) of the NGPA which provides that, for purposes of determining whether a reservoir has produced in commercial quantities prior to April 20, 1977, a rebuttable presumption exists that such production did not take place if gas has not been sold and delivered from the reservoir before that date.

One comment suggested that an additional rebuttable presumption be created where the producer could show that the volumes sold do not constitute "commercial quantities." If gas has been sold and delivered in commerce the Commission can reach no other conclusion than that there has been "production in commercial quantities." Therefore, the suggestion is rejected.

Several comments stated that use of the "beneficial economic use" test distorts Congressional intent because evidence of *any* beneficial economic use will result in a finding that gas has been produced in commercial quantities. However, the comment is erroneous because not every use qualifies as a "beneficial economic use." The definition in § 270.102(b)(4) specifically excludes such beneficial uses as testing wells or other production related field use from the definition of "production in commercial quantities." Such uses would include but would not be limited to reinjection, fuel for compressors, camp quarters, and processing.

Another comment suggested that the jurisdictional agency should determine what constitutes "beneficial economic use" after considering all the available evidence. The Commission agrees with this comment but disagrees that the regulations bar such a determination. In fact, the Commission believes that the regulations require that a jurisdictional agency make such a determination, based on substantial evidence, in order to classify gas as produced from a new reservoir or a new onshore well and to determine that such gas is subject to the section 102 price.

The Commission received several comments on issues related to the behind-the-pipe exclusion in section 102(c)(1)(C)(ii) of the NGPA. Under section 102(c)(1)(C)(ii), if a reservoir could have produced in commercial quantities had a completion location been established from the old well which penetrated it and which produced oil or natural gas in commercial quantities, the reservoir does not qualify as a new onshore reservoir under section 102. One comment suggested that:

> Production in commercial quantities needs to reflect the volumes that could have been produced at the time the reservoir was first discovered at the then current prices and then current costs.

The Commission disagrees with this suggestion. The Statement of Managers states:

> The behind-the-pipe exclusion prohibits natural gas produced from any reservoir from qualifying as new natural gas under this definition if natural gas could have been produced in commercial quantities from such reservoir through such old well before April 20, 1977. The phrase "could have been produced" is intended by the conferees to refer to the *capability of the reservoir to produce* without regard to whether actual production capability existed. [Emphasis added]

The language of the Statement of Managers, the existence in the statute of a rebuttable presumption that production in commercial quantities has occurred if there has been a sale and delivery, and the absence of the requirement for suitable facilities in the behind-the-pipe exclusion lead the Commission to conclude that the Congress did not wish to define "could have been produced in commercial quantities" in section 102(c)(1)(C)(ii)(II) in a manner similar to the sale and delivery test for "production in commercial quantities." In fact, the Commission believes that the text of the statute, the legislative history, and policy considerations allow use of a capability test for the term "could have been produced" in the behind-the-pipe exclusion. The capability test does not take into consideration the necessity for or cost of pipeline facilities, gathering or processing plants. It does not depend on the actual marketability of the gas prior to April 20, 1977. The capability test is restricted in its scope to the capability of the reservoir to produce prior to April 20, 1977. Thus costs and prices, regardless of their time reference, are irrelevant, and the comment must be rejected.

Another comment on the behind-the-pipe exclusion noted that small producers who would ordinarily drill reservoirs passed over by large producers as insignificant, would frequently be subject to the behind-the-pipe exclusion because the reservoir could have produced in commercial quantities. The comment suggested that the small producer be permitted to collect the section 102 price for such natural gas. While the Commission recognizes the possible hardship which the exclusion imposes upon the small producer, the statutory language is explicit and does not provide for an exemption from the behind-the-pipe exclusion for small producers. Therefore, the suggestion must be rejected.

The special rule in paragraph (d) of § 271.204 implements section 102(c)(1)(C)(iii) and (iv) of the NGPA which excludes from the category "new natural gas" any gas produced from an old well for which suitable production and delivery facilities (other than emergency facilities) were in existence on April 20, 1977. Several comments disagreed with the special rule in § 271.204(d) defining "suitable facilities for the production and delivery to a pipeline" as those facilities which were "installed" or "substantially installed and [for which] additional facilities necessary for such production and delivery were readily available and could have been installed by April 20, 1977." The comments emphasized that the statutory language refers to facilities "in existence on April 20, 1977," and argued that expansion of the definition to include facilities which were "substantially installed" is erroneous. The comments urged that § 271.204(d)(2) be deleted. The Commission addressed this issue in the preamble to the interim regulations and maintains its position that the term "suitable facilities . . . in existence on April 20, 1977," may include additional facilities and equipment which were readily available and could have been installed by April 20, 1977.

Several comments suggested that the exclusion for emergency sales facilities be mentioned in § 271.204(d). The Commission has already dealt with the issue of emergency sales facilities by including the parenthetical phrase "(but subject to section 102(c)(1)(C)(iv) thereof)" in § 271.204(d) of the interim regulations. This phrase was added to reflect the statutory provision that facilities installed solely for purposes of making sales under section 6 of the Emergency Natural Gas Act of 1977 or for the purposes of making 60-day emergency sales not be considered "suitable facilities" within the meaning of section 102 of the NGPA. The final regulations retain this provision.

III. Public Procedures and Effective Date

The regulations in Subpart B of Part 271 were originally proposed for comment in November of 1978 and issued as interim regulations on December 1, 1978 (43 FR 56448, Dec. 1, 1978). For 60 days thereafter comments were received and during that period, public hearings were held on these regulations. By this process, the Commission complied with the provision of section 502(b) of the NGPA which requires that "[t]o the maximum extent practicable," an opportunity for the oral presentation of data, views, and arguments be afforded for certain regulations under the NGPA. The amendments to Subpart B of Part 271 contained in this order have been issued after a thorough review of these comments.

Accordingly, the Commission finds that further notice and public procedure on these regulations are unnecessary and impractical and that good cause exists to dispense with additional notice and public procedure. Because the amendments made in Subpart B of Part 271 are clarifying and interpretative in nature, Subpart B, as amended, is effective as final regulations immediately with regard to jurisdictional agency determinations which have not become final under § 275.202 as of the day before the date of issuance of this order.

(Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.*; Natural Gas Policy Act of 1978, Pub. L. 95–621, 92 Stat. 3350; Department of Energy Organization Act, 42 USC 7107 *et seq.*; E.O. 12009, 42 FR 46267.)

In consideration of the foregoing, Subpart B of Part 271, Subchapter H, Chapter I, Title 18, Code of Federal Regulations, is issued as final regulations as set forth below, effective immediately as set forth above.

By the Commission.
Kenneth F. Plumb,
Secretary.

[¶ 30,075]

44 F. R. 48184 (August 17, 1979)

18 CFR Part 281

[Docket No. RM79-15]

Order Granting Transcontinental Gas Pipe Line Corporation's Applications For Rehearing

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) hereby gives notice that 18 CFR 281.202 is amended by deleting

"Transcontinental Gas Pipe Line Corporation." This amendment clarifies the status of the settlement governing curtailment on Transco's system.

EFFECTIVE DATE: August 2, 1979.

FOR FURTHER INFORMATION CONTACT: Kenneth F. Plumb, Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426 (202) 275–4166.

Before Commissioners: Georgiana Sheldon, Acting Chairman; Matthew Holden, Jr., and George R. Hall.

Issued: August 2, 1979.

Order No. 29—our Final Rule implementing Section 401(a) of the Natural Gas Policy Act of 1978 (the "NGPA")—listed Transcontinental Gas Pipe Line Corporation (Transco) as being subject to it.[1] Transco has sought rehearing,[2] arguing that it should not be made subject to Order No. 29 and its requirement for filing a revised curtailment tariff in the form therein specified for the reason that the Commission had just shortly prior to issuance of Order No. 29 approved a settlement [3] which by its terms, as interpreted and enforced by our orders [4] thereon, provides a satisfactory means of implementing Section 401(a) on Transco's system for the duration of the settlement.[5] We agree. Our concurrence is, however, conditioned upon Transco filing an amendment to its existing tariff as it suggests in its application for rehearing.[6] That filing shall be made by October 1 with an effective date of November 1, 1979.

At the time of promulgating Order No. 29, we said:

> [N]othing in the rule precludes any interstate pipeline and its customers from proposing, as a settlement, a curtailment plan that differs from that set out in our rule. Such a settlement will be evaluated by the Commission in light of its responsibility to meet the statutory goal of protecting, to the maximum extent practicable, high priority users and essential agricultural uses.[7]

The settlement we approved in Docket No. RP72–99 on January 19, 1979 is a comprehensive one, resolving many controversies of long-standing. Accordingly, we evaluated it not only in accordance with the NGPA but also the

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[1] The Final Regulation for the Implementation of Section 401 of the Natural Gas Policy Act, Order No. 29, Final Rule, Docket No. RM79–15, 18 CFR Part 281 (issued May 2, 1979). Order No. 29–A (June 15, 1979) and Order 29–B (July 20, 1979) extended certain dates specified in the base order.

[2] Application for Rehearing or Clarification and Request for Immediate Partial Stay of Order No. 29, June 1, 1979. Numerous other petitions for rehearing of Order No. 29 have also been filed. We take no present action with respect to those requests. They will be addressed later. We act at this time on Transco's application in order to clarify the status of the settlement governing curtailment on that system. In this regard, see the companion order to this one issued today in Docket No. RP72–99 which denies rehearing of our January 19 order approving the settlement. Our action here moots Transco's request for partial stay as well as the filings made in response thereto. It will therefore be unnecessary for the Commission to act on those filings.

[3] See Order Approving and Adopting Settlement, *Transcontinental Gas Pipe Line Corporation*, Docket No. RP72–99 (January 19, 1979). This order was preceded on January 4, 1979 by one entitled "Order Interpreting Proposed Settlement Requesting Comments and Setting Oral Argument." Also, we are today issuing an Order Denying Rehearing of the January 19 order.

[4] See orders listed in immediately preceeding note.

[5] Pursuant to our January 19 order, Transco filed tariff sheets on January 29, 1979 implementing the settlement plan. In accordance with the settlement and our orders, the plan becomes effective November 1, 1978. The settlement plan will continue in effect so long as Transco's supplies stay above the benchmark of 636 MMdt service to Transco's so-called large volume customers. See January 4 order (p. 5) quoting Article II of the settlement agreement.

[6] P. 13, note 13. Transco's proposal is to extend beyond October 31, 1979 the tariff sheets filed March 16, 1979 in implementation of the Interim Curtailment Rule. See Interim Regulation for the Implementation of Section 401 of the Natural Gas Policy Act of 1978, Interim Curtailment Rule, Docket No. RM79–13 (issued March 6, 1979) and Order Accepting Tariff Sheets, *Florida Gas Transmission Company, et al.* Docket No. TC79–5, *et al.*, issued March 30, 1979 accepting Transco's tariff filing effective April 1, 1979. In its instant petition for rehearing, Transco asserts that this procedure "may in actuality provide superior protection [to Order No. 29] to essential agricultural users."

[7] Order No. 29, Preamble (*mimeo*, pp. 10–11).

Natural Gas Act. Nothing further (other than the above mentioned tariff amendment) will be required at this time.

The Commission finds and orders: Subject to filing an amendment to its tariff as discussed in the text, Transco's request for rehearing of Order No. 29 is granted. In order to implement the substance of this grant, Title 18 of the Code of Federal Regulations is amended in section 281.202 by deleting "Transcontinental Gas Pipe Line Corporation." This amendment is being made at this time in order to clarify the status of the settlement governing curtailment on Transco's system pursuant to our orders entered in Docket No. RP72-99. We are today also issuing an Order Denying Rehearing in Docket No. RP72-99 of our January 19, 1979 Order Approving and Adopting Settlement. Section 553(d) of Title 5, United States Code, requires that an amendment to a rule not become effective less than thirty days after its publication unless the agency promulgating the amendment finds good cause to waive this requirement and publishes this finding together with the amendment. The requirement for coordinating our action herein with those taken in Docket No. RP72-99 establishes good cause to waive the section 553(d) requirement in this case. Therefore, the amendment is issued effective immediately.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,076]

44 F. R. 48660 (August 20, 1979)

18 CFR Parts 270, 271, and 273

[Docket No. RM79-60]

Publication of Prescribed Maximum Lawful Prices Under the Natural Gas Policy Act of 1978

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: This rule amends certain Federal Energy Regulatory Commission's regulations implementing the Natural Gas Policy Act of 1978 (NGPA). By this amendment the Commission revises its method of publication of the maximum lawful prices under the NGPA and issues a compilation of Prescribed Maximum Lawful Prices under the NGPA for the months of August, September and October of 1979. Section 101(b)(6) of the NGPA requires that the Commission compute and make available prices and inflation adjustments at least five days before the beginning of any month for which such figures apply.

EFFECTIVE DATE: July 25, 1979.

FOR FURTHER INFORMATION CONTACT: Mark Magnuson, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 275-4850.

July 25, 1979.

A. Background

On December 1, 1978, the Federal Energy Regulatory Commission (Commission) issued Interim Regulations (43 FR 56448, December 1, 1978), implementing the Natural Gas Policy Act of 1978 (NGPA), Pub. L. No. 95-621, 92 Stat. 3350.

On April 27, 1979, the Commission issued the Publication of Prescribed Maximum Lawful Prices Under the NGPA under Docket No. RM79-39 (44 FR 26068, May 4, 1979).

Sections 271.101(a), 271.202, 271.302, 271.402(a), 271.402(c)(4), 271.602, 271.702, 271.802, and 271.902 of the Commission's regulations under the NGPA set forth maximum lawful prices per MMBtu (per Mcf for minimum rate gas) for deliveries made in December, 1978 through July, 1979. Section 271.102(c) set forth the monthly inflation adjustment factors. Section 101(b)(6) of the NGPA requires that the Commission compute and make available maximum lawful prices and inflation adjustments at least five days before the beginning of any month for which such figures apply. Pursuant to that mandate, the Commission is amending its regulations implementing the NGPA to issue the maximum lawful prices for the months of August, September and October of 1979. In addition, the Commission is revising its method of announcing such prices by publishing for each quarter a single set of tables which will specify the maximum lawful prices and inflation adjustments up to and including that quarter's. Table I specifies the maximum lawful prices for gas subject to sections 102, 103, 106(b)(1)(B), 107, 108 and 109 of the NGPA; Table II specifies the prices for sections 104 and 106(a); Table III sets forth the inflation adjustments.

B. Summary of Amended Regulations

The Commission's regulations under the NGPA are being amended by the publication of Tables I, II and III establishing the maximum lawful prices and inflation adjustments for August, September and October 1979. This amendment affects the following subparts of Part 270 and Part 271 of the regulations: Part 270, Subpart A—General Rules and Definitions (§ 270.101(c)); Part 271, Subpart A—Summary Tables and Calculations (§§ 271.101(a) and 271.102(c)); Subpart B—New Natural Gas and Certain Natural Gas Produced from the Outer Continental Shelf (§ 271.202); Subpart C—New, Onshore Production Wells (§ 271.302); Subpart D—Natural Gas Committed or Dedicated to Interstate Commerce (§ 271.402(a), and 271.402(c)(4)); Subpart F—Intrastate Rollover Contracts (§ 271.602); Subpart G—High-cost Natural Gas (§ 271.702); Subpart H—Stripper Well Natural Gas (§ 271.802); and Subpart I—Other Categories of Natural Gas (§ 271.902).

C. Public Procedure and Effective Date

The Commission is making these amendments effective upon the date of issuance of this order upon a finding that it is impracticable and unnecessary to comply with the notice and public procedure provisions of 5 U.S.C. 553. Section 101(b)(6) of the NGPA requires that maximum lawful prices and inflation adjustments be made available by the Commission at least five days before the beginning of the month to which they apply. However, publication of the GNP Implicit Price Deflator by the Department of Commerce at least 8 days before the most recent calendar quarter, does not afford sufficient time for comment before the maximum lawful prices and inflation adjustments go into effect. Notice and public comment are unnecessary as well as impracticable because the changes in organization change the form but not the substance of the regulations and because the changes in prices and inflation adjustments are mandated by statute. Good cause exists to make these amendments regarding rate changes for August, September and October, 1979, effective immediately. Such a procedure is required in order to comply with the NGPA, and, if such a procedure is not followed, producers may bill and file incorrectly for the affected categories of gas.

(Natural Gas Act, as amended, 15 U.S.C. § 717 *et seq.*; Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350; Department of Energy Organization Act, 42 U.S.C. 7107, *et seq.*, E.O. 12009, 42 FR 46267).

In consideration of the foregoing, Parts 270 and 271 of Subchapter H, Chapter I, Title 18, Code of Federal Regulations, are amended as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,077]

44 F. R. 48664 (August 20, 1979)

18 CFR Part 274 and 275

[Docket No. RM79-62; Order No. 41]

Natural Gas; Determinations by Jurisdictional Agencies; Commission Determinations and Commission Review of Jurisdictional Agency Determinations

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Regulations.

SUMMARY: The Federal Energy Regulatory Commission is amending and making final certain of the interim regulations published December 1, 1978, concerning determinations by Federal or State agencies having regulatory jurisdiction with respect to the production of natural gas. The regulations apply to determinations that a well is eligible for a particular maximum lawful price established by the Natural Gas Policy Act of 1978. The Commission also amends § 275.202 to reflect a change in these regulations.

EFFECTIVE DATE: August 1, 1979.

FOR FURTHER INFORMATION CONTACT: Carol Lane, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8100–H, 825 North Capitol Street NE., Washington, D.C. 20426 (202) 275–4867.

Final Regulations for Subparts A, C, D, and E of Part 274 Concerning Determinations by Jurisdictional Agencies under the Natural Gas Policy Act of 1978 and Amendment to § 275.202 (Order No. 41).

Issued: August 1, 1979.

I. Background

On December 1, 1978, the Federal Energy Regulatory Commission (Commission) issued interim regulations (43 FR 50448, December 1, 1978) implementing certain sections of the Natural Gas Policy Act of 1978 (NGPA). Part 274 of the interim regulations applies to initial determinations by jurisdictional agencies that a well is eligible for a particular maximum lawful price established by the NGPA. This order amends Subparts A, C, D and E [1] of Part 274. Subpart A applies to the jurisdictional agency determination process and the mechanism by which it gives notice of same to the Commission. Subpart C describes the procedures under which a jurisdictional agency may enter into an agreement with the Commission to waive its authority to make determinations. Subpart D provides for Commission discretion to delegate to certain State regulatory agencies the Commission's authority under Part 276 to receive filings under that part. Subpart E defines jurisdictional agency, contains a table of agencies by State, and defines Federal lands. This order also amends § 275.202 of the Final Regulations for Subpart B, Part 275, to reflect a change in that section necessitated by a change in Part 274, Subpart A.

II. Summary of Comments and Revisions

A. *Subpart A.* Subpart A of Part 274 relates to the procedures by which jurisdictional agencies make determinations in accordance with section 503 of the NGPA. Section 274.101 lists the categories of natural gas to which Part 274 applies.

Section 274.102 provides that a determination has been made once it is "administratively final" before the jurisdictional agency. If, for example, a State agency's decisions are normally subject to rehearing under its usual procedures, the determination is not final until the period for rehearing expires or rehearing is sought and denied.

Section 274.103 stipulates that the procedures applicable to determinations by jurisdictional agencies shall be those procedures prescribed by State law for making NGPA determinations, or for making comparable determinations. The Commission received a number of comments on this section which proposed that uniform standards be established for jurisdictional agency proceedings with respect to public notice, intervention, conduct of hearings, and so forth. We have rejected all of these suggestions because we do not believe we have the statutory authority to determine procedural rules for proceedings before the jurisdictional agencies. Section 503(c)(3) of the NGPA states:

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[1] Final regulations for Part 274, Subpart B (which prescribes the filing requirements which apply to applications for determinations) will be adopted separately, after issuance of final regulations for Subparts B, C, G and H of Part 271.

> Determinations of a Federal or State agency referred to in subsection (a)(1) shall be made in accordance with the procedures generally applicable to such agency for the making of such determinations or comparable determinations under the provisions of Federal or State law, as the case may be, pursuant to which they exercise their regulatory jurisdiction. The Commission may prescribe the form and content of filings with a Federal or State agency in connection with determinations made under this section.

The Statement of Managers indicates that questions regarding procedures followed by the jurisdictional agencies are to be reviewed directly by the State or Federal court having jurisdiction to hear such appeals in accordance with applicable State or Federal law. (S. Rep. No. 95–1126, 95th Cong., 2d Sess. 119 (1978)). Since Congress specifically provided that proceedings before the jurisdictional agencies were in accord with their generally applicable procedures and that review of procedures used was the province of the courts, the Commission lacks the statutory authority to prescribe the procedures suggested in the comments. In view of the Commission's lack of authority, comments concerning proceedings before jurisdictional agencies should be directed to those agencies.

The final regulations in § 274.104 are based on section 503(a)(2) of the NGPA, which provides that each notice of determinations shall "include such substantiation and be in such manner as the Commission may, by rule, require." Our regulations provide that a jurisdictional agency must notify the Commission within 15 days after making a determination. Notice of an affirmative determination must include: (1) A list of participants in the proceeding and persons who submitted or sought to submit written comments; (2) a statement indicating whether the matter was opposed before the jurisdictional agency; (3) the information set forth in § 274.105 as applied to the determination in question, unless the jurisdictional agency has filed a report with the Commission in accordance with § 274.105; (4) a copy of the application and a copy or description of other materials upon which the jurisdictional agency relied in the course of making the determination, together with any information which may be inconsistent with its determination; (5) the information required to be filed by the applicant under Subpart B of Part 274 or § 274.207; and (6) a statement sufficient to enable a person examining the notice to ascertain the basis for the determination, without reference to data not contained in the record.

Item (4) above differs somewhat from item (4) as it appeared in the interim regulations. The change was made in response to a comment which asserted that any information inconsistent with the agency's determination should be required to be included with the notice. In order to clarify any misunderstanding in this regard, we have amended § 274.104(a)(4) to provide that an agency must include a copy or description of both the materials on which it relied in making the determination, and any information inconsistent with the determination which came to its attention in the course of making the determination.

Item (5) above also differs somewhat from item (5) as it appeared in the interim regulations. The item formerly required, *inter alia*, an "affirmative finding" by the jurisdictional agency that the notice included all the information required to be filed by the applicant. After some experience with this regulation, the Commission has found that in certain cases the "affirmative finding" is made, but some of the information itself is omitted. This makes it necessary for the Commission to act without having before it the minimum information upon which to review the determination for substantial evidence. We believe that a reasonable means of dealing with such a situation is to toll the Commission's 45-day review period and to notify the agency that the notice is incomplete. Accordingly, we have amended item (5) to require that the notice from the jurisdictional agency shall include "the information required to be filed by the applicant under Subpart B of Part 274 or under § 274.207." If any of this information is not included, the Commission may, pursuant to § 275.202(b), toll the review period and notify the jurisdictional agency that the notice is incomplete.

Item (6) above is an addition to the interim regulations. It has been inserted because the Commission has found, after several months of experience in reviewing jurisdictional agency determinations, that notices submitted by the agencies are not always presented in a manner which is fully understandable to the Commission. For example, if a notice that a well qualifies under section 103 as a new, onshore production well includes a plat to establish a required fact, and the plat uses a set of unfamiliar symbols and contains no legend explaining those symbols, the Commission may not be able to ascertain the jurisdictional agency's basis for making the section 103 determination. In our review of the notice, we may be unable on the basis of the plat to find substantial evidence that the determination rests on a finding that the well meets certain well spacing requirements and is not located within an existing proration unit. Accordingly, we have added language in a new subsection § 274.104(a)(6) which requires an explanatory statement, including factual findings, which describes the basis for the determination. We have also changed § 275.202(b), (under which the Commission may notify the jurisdictional agency if a notice is incomplete) to reflect this additional language.

One comment on § 274.104 proposed that the complete record of the proceedings before the jurisdictional agency be submitted to the Commission for review, rather than a copy or description of the materials in the record. In this respect, our several months of experience in reviewing jurisdictional agency notices is again relevant. On the basis of this experience, we have concluded that we will be able to meet our statutory obligation to review determinations by looking to the written notice submitted to the Commission by the jurisdictional agency pursuant to subparagraphs (1) through (6) of § 274.104(a). A requirement that the complete record be filed would be unduly burdensome, in that it would necessitate the copying and transmittal or large amounts of technical data for a single application.

Notice of a negative determination by a jurisdictional agency must be given to the Commission within 15 days, pursuant to the requirements of § 274.104(b). Where an applicant or any aggrieved party so requests within 15 days following the negative determination, the notice shall include all of the information required to be transmitted to the Commission when an affirmative determination is made pursuant to clauses (1) through (6) of § 274.104(a). This rule has been amended to provide that where the applicant or aggrieved party makes such a request, the jurisdictional agency shall submit the additional information within 20 (rather than 15) days after the determination has been made. This will give the agency a maximum of 20 and a minimum of 5 days in which to comply with the request.

Section 274.105 provides an alternative to the procedures prescribed in § 274.104(a)(3). If a jurisdictional agency chooses to adopt the § 274.105 option, it may file with the Commission a report in which it undertakes to make the necessary determinations and in which it describes of the procedures to be followed in making them. The agency will then be relieved of the obligation to describe its procedures in each individual case.

One commentor stated that § 274.105, along with § 274.104(a)(3), should be eliminated from the regulations because both sections assert Commission jurisdiction over jurisdictional agency procedures. In considering this comment, we note that the sections in question require that two kinds of information be submitted: (1) the filing requirements applicable to the particular section of the NGPA under which the determination is being made, and (2) an explanation or description of the procedures and rules under which the jurisdictional agency operates. With respect to item 1, the NGPA stipulates in section 503(c)(3) that ". . . The Commission may prescribe the form and content of filings with a Federal or State agency in connection with determinations made under this section." With respect to item 2, the regulations do not prescribe procedures; they merely require a description or explanation of those procedures. Accordingly, we do not believe that either § 274.104(a)(3) or § 274.105 asserts unlawful Commission jurisdiction over the procedures of jurisdictional agencies.

B. *Subpart C.* Subpart C of Part 274 implements section 503(c)(2) of the NGPA by prescribing the procedures by which a jurisdictional agency and the Commission may enter into an agreement under which the former may waive authority to the latter to make NGPA determinations.

Section 274.302 provides that an agency may file a request for waiver to the Commission, specifies the contents of such a request, and requires an agency to state the reasons for the request. If the Commission decides to enter an agreement of waiver, it may do so. The Commission may impose such terms and conditions that it deems appropriate. The provisions of § 274.303 specify the method under which a revocation or termination of the agreement shall occur.

One State filed a comment suggesting that the Commission does not have the discretion to refuse any request for a waiver. We disagree. Section 503(c)(2)(A) of the NGPA stipulates that a Federal or State agency may waive its authority to make determinations "by entering into an agreement" in accordance with subparagraph (B). Subparagraph (B), in turn, provides that any waiver may be made "only by a written agreement" between the agency and the Commission. We believe that this language provides the Commission with the discretion to agree or not to agree to a proposal for a waiver and thus to grant or refuse a request for waiver.

C. *Subpart D.* Subpart D of Part 274 authorizes delegation, to certain State regulatory agencies, of the Commission authority under Part 276 to receive filings from intrastate pipeline purchasers of gas sold pursuant to sections 105 and 106(b) of the NGPA.

Section 274.401(b) limits the "State agency" to which such a delegation may be made to one with jurisdiction over the rates and charges of the intrastate pipelines that would be making the required filing. One commentor asked whether the Commission has statutory authority to make a delegation to this "State agency", since such an agency is nowhere mentioned in the NGPA. In this respect, we note that section 501(c) of the NGPA provides that the Commission "may delegate to *any State agency* (with the consent of such agency) any of its functions with respect to sections 105, 106(b) and 109(a)(1) and (3)." (emphasis added) Accordingly, we find no merit to this comment.

Another comment proposed that the Commission refrain from exercising its statutory authority to delegate receipt of intrastate pipeline filings under Part 276. This comment asserted that the Commission should be the basic repository for these reports in order that it may be kept properly informed of the actual operation of sections 105 and 106(b). In general, while we believe it is consistent with the intent of the NGPA to shift a greater part of the total compliance role of natural gas regulation to the States, the Commission's overall responsibility to enforce the NGPA, and the fact that intrastate sales will be regulated for the first time under the NGPA, argue in favor of the Commission's retention of this role at this particular time.

Accordingly, we agree with this comment and will amend § 274.401, leaving the delegation procedure as it stands, but adding a provision which establishes that in cases where the Commission delegates to a State agency its authority to receive Part 276 filings from an intrastate pipeline purchaser, the delegation agreement shall contain terms by which the Commission will be provided with such copies of Part 276 filings as it may require.

Several producers raised an additional issue with respect to the above-described intrastate pipeline filings. They argued that the jurisdictional agency (as defined in section 503(c) of the NGPA) should be designated as the recipient of the filings, rather than the State agency regulating intrastate pipelines. It was argued that such a rule would eliminate the possibility of a bifurcated structure's emerging in those States in which two separate State agencies could have responsibilities regarding first sales under the NGPA. We agree that this suggestion has merit in terms of consolidating NGPA information. However, we believe that it is more important that these filings be directed to the State agency as specified in § 274.401(b) in order to assist it in regulating the intrastate pipelines within its jurisdiction and to enable such agency to excercise its expertise in this area. For this reason we have not adopted the proposal.

Another comment on § 274.401 suggested that the Commission provide for delegation of authority to receive reports relating to section 109(a)(1) and (3). We note that exercise of the delegation authority in § 274.401 will operate to permit intrastate pipelines purchasing section 105 and 106(a) gas to file Part 273 reports with the appropriate State agency. However, Part 276 imposes no reporting duty on intrastate pipelines purchasing section 109 gas. For this reason section 109 has not been included within the scope of § 274.401.

In response to another comment on § 274.401, the language of the section has been amended to clarify the fact that the reports required to be filed by an intrastate pipeline should reflect sales (not reports) made pursuant to sections 105 and 106(b).

D. *Subpart E.* Subpart E of Part 274 defines jurisdictional agency, contains a table of agencies by State, and defines Federal lands.

A comment on this subpart suggested that the Commission does not possess statutory authority to prescribe the names of State and Federal jurisdictional agencies. In response to the concern expressed in the comment, we have amended § 274.501 both to reflect the definition of jurisdictional agency contained in section 503(c) of the NGPA, and to make it clear that § 274.501(a)(2) lists the agencies which have notified the Commission of their authority to make determinations. We believe that such a listing provides useful information to persons seeking to apply for NGPA determinations.

Several State jurisdictional agencies and the Geological Survey of the Department of the Interior have notified the Commission that the list set forth in this section requires modification or correction with respect to their particular addresses. Accordingly, we are amending § 274.501(a)(2) to reflect the appropriate changes. We are also amending § 274.501(c)(2) to reflect the fact that the Osage Indian Agency retains jurisdiction over wells the surface location of which is on lands within the boundaries of the Osage Reservation.

Several comments asked which jurisdictional agency should make the determination when a well is located on a divided-interest lease involving Federal (or Indian) and private (or State) ownership. The Commission believes that the most reasonable approach in such a case is to provide that where the divided-interest lease pertains to a drilling unit which is drained by one well, (1) the Federal jurisdictional agency shall make the determination where the majority lease interest is Federal (or Indian); (2) the State agency shall make the determination where the majority interest is private (or State); and (3) the State agency shall make the determination where the interest is divided equally. As noted below, however, the two agencies could agree to a different arrangement.

In those cases where a drilling unit is drained by two or more wells, the Federal jurisdictional agency shall make the determination if the completion location of the well in question is located on a Federal lease, and the State jurisdictional agency shall make the determination if the completion location is on a private lease. Section 274.501 has been amended to reflect this approach, although, again, the agencies could agree to a different arrangement.

Section 274.501(f) of the regulations provides that if the U.S. Geological Survey and any State jurisdictional agency enter into an agreement authorizing the State agency to make determinations with respect to wells located on Federal lands, or vice versa, the agency authorized in the agreement shall be considered the jurisdictional agency with respect to wells on the designated lands upon the filing of such agreement with the Commission.

One comment suggested that this section be deleted because the Act does not provide that one agency may delegate its jurisdiction to another. We have not made this change. Section 274.501(f) was included in the regulations to reflect the fact that an agency having regulatory jurisdiction with respect to the production of natural gas may, apart from any provision contained or not contained in the NGPA, agree to transfer or delegate such jurisdiction. Should such an event occur, the agency designated in the agreement would become "the Federal or State agency having regulatory jurisdiction with respect to the production of natural gas." Accordingly, the Commission would be required by section 503(c)(1) of the NGPA to recognize that agency as the jurisdictional agency authorized to make determinations with respect to any wells on land covered by the agreement.

III. Public Procedures and Effective Date

The regulations in Subparts A, C, D, and E of Part 274 were originally proposed for comment in November of 1978 and issued as interim regulations on December 1, 1978 (43 FR 56448, Dec. 1, 1978). For 60 days thereafter comments were received, and during that period public hearings were held on these regulations. By this process the Commission complied with the provisions of section 502(b) of the NGPA, which requires that "(t)o the maximum extent practicable," an opportunity for the oral presentation of data, views, and arguments be afforded for certain regulations under the NGPA.

The amendments to Subparts A, C, D, and E of Part 274 contained in this order rest upon consideration given to the information received during the above-described notice, comment, and hearing process, as well as upon comments received via the FERC "Hot Line." The Commission finds that further notice and public procedure with respect to these rules is unnecessary. The Commission also finds that good cause exists to dispense with the publication requirements of 5 U.S.C. § 553(d)(1) in order that both jurisdictional agencies and the Commission may more readily administer their duties under the NGPA.

Accordingly, Subparts A, C, D, and E of Part 274 and Subpart B of Part 275, as amended, are effective as final regulations immediately with regard to applications filed prior to the date of issuance of this order but for which determinations have not yet become final under § 275.202 as of the day before the date of issuance of this order.

(Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, Department of Energy Organization Act, 42 USC §§ 7107 *et seq.*, E.O. 12009, 42 FR 46267.)

In consideration of the foregoing, Subparts A, C, D, and E of Part 274, Subchapter H, Chapter I, Title 18, Code of Federal Regulations, are issued as final regulations as set forth below, effective immediately. Subpart B of Part 275 is amended, as set forth below, effective immediately.

By the Commission.
Kenneth F. Plumb,
Secretary.

[¶ 30,078]

44 F. R. 49651 (August 24, 1979)

18 CFR Parts 271 and 274

[Docket No. RM79-72; Order No. 43]

New Onshore Production Wells; Final Regulations and Amendment to Interim Regulations

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Regulations and Amendment to Interim Regulations.

SUMMARY: The regulations issued in final form implement section 103 of the Natural Gas Policy Act of 1978 which sets ceiling prices for new, onshore production wells and represents several modifications of the Interim Regulations issued December 1, 1978. In addition, the Commission is amending the requirements for filing with jurisdictional agencies for this type of gas to track the change made by the final regulations.

EFFECTIVE DATE: August 20, 1979.

FOR FURTHER INFORMATION CONTACT: Thom Hirsch, Office of the General Counsel, Federal Energy Regulatory Commission, Room 4008-E, 825 North Capitol Street, NE., Washington, D.C. 20426 (202) 275-0431.

Before Commissioners: Georgiana Sheldon, Acting Chairman; Matthew Holden, Jr., and George R. Hall.

In the matter of final rule amending regulations on natural gas from new, onshore production wells and amendment to the filing requirements in § 274.204 of the interim regulations.

Issued: August 20, 1979.

Background

The Commission is issuing final regulations implementing section 103 of the Natural Gas Policy Act of 1978 (NGPA), Pub. L. No. 95-621, which concerns new, onshore production wells. The Commission also is amending a portion of § 274.204 of its interim regulations regarding filing requirements for new, onshore production wells.

On December 1, 1978, the Commission issued interim regulations (43 FR 56448) implementing the NGPA. Since issuing the interim regulations, the Commission has held numerous public hearings and provided opportunity for written comments on the regulations. One result of the hearings and the written submissions is this order which promulgates §§ 271.301 through 271.305 as final rules and amends § 274.204 of the interim regulations. Sections 271.301 through 271.305 concern new, onshore production wells under section 103 of the NGPA. Section 274.204 prescribes filing requirements for applications with jurisdictional agencies which request a determination that gas is produced from a new, onshore production well.

The NGPA established maximum lawful prices for first sales of natural gas. The applicable price depends upon which of the several price categories the gas qualifies for. This in turn depends, among other things, on the characteristics of the well that produced the gas. The price category of section 103 covers natural gas from so-called new, onshore production wells. These are wells: 1) The surface drilling of which began on or after February 19, 1977, 2) Which satisfy the applicable Federal or State well-spacing requirements and 3) Which are not within certain proration units. These statutory requirements are refined in §§ 271.301 through 271.305.

Discussion of Comments

Most of the comments on §§ 271.301 through 271.305 of the interim regulations concerning new, onshore production wells focused on the special rule established in § 271.305 which applies to wells within existing proration units. Generally, a new well drilled within an existing proration unit cannot qualify as a new, onshore production well.

The special-rule provides for an exception where a jurisdictional agency making the section 103 determination finds that the new well is necessary to effectively and efficiently drain a portion of the reservoir covered by the proration unit, which cannot be effectively and efficiently drained by any existing well within the unit. Two State public service commissions allege that there is no authority in the NGPA for the special rule and that § 271.305 of the regulations should be eliminated. The comments allege that a well drilled within an existing proration unit simply cannot qualify under section 103.

The Joint Explanatory Statement of the Committee on Conference speaks directly to the point raised by these State commissions:

> In some instances, a State or Federal agency may designate a proration unit for a reservoir which it later determines cannot effectively or efficiently be drained by a single well. In such case, the State or Federal agency may allow another well to be drilled on the same proration unit. The conferees do not intend a new well to be disqualified as a new onshore production well in such cases. S. Rep. No. 1126, 95th Cong., 2 Sess. 81 (1978).

It is clear that Congress contemplated that in certain cases wells drilled in existing proration units could qualify as new, onshore production wells under section 103 of the NGPA. Thus, § 271.305 is not without a basis in the NGPA.

Section 271.305(a) of the interim regulations describes the jurisdictional agency determinations to which the special rule applies. One comment requests that language be added to § 271.305(a)(2)(i) to narrow the coverage of that section to include only reservoirs that produced gas in commercial quantities before February 19, 1977.

The Commission finds no statutory basis for this proposal. Section 103(c)(3)(C)(i) of the NGPA mentions reservoirs that produced gas in commercial quantities, but contains no specific date in reference to these reservoirs. However, to make § 271.305(a) clearer, the Commission will amend this section to track the exact language of section 103(c)(3) of the NGPA. This change is only for purposes of clarification and should not be construed as a change in Commission policy on the scope of the special rule applicable to existing proration units.

Amending § 271.305(a) to track the language of section 103 also will resolve another apparent point of confusion that is raised in the comments. One comment states that the wording of § 271.305(a)(2)(i) and (ii) is overly broad and ostensibly makes the special rule (for wells drilled within existing proration units) applicable even where no other well is located within the same proration unit as the well for which the section 103 determination is sought. This comment alleges that as long as another well produced or was capable of producing natural gas in commercial quantities from the same reservoir as the subject well, the special rule applies and the finding required by § 271.305(b) would have to be made in order for the subject well to qualify as a new, onshore production well.

As the Joint Explanatory Statement of the Conferees on the NGPA makes clear, the Congress in discussing section 103(c) of the Act envisioned that a special rule for wells drilled within existing proration units would be needed in that situation where the subject well is drilled within the same proration unit and into the same reservoir as another well which produced or was capable of producing natural gas in commercial quantities. The Commission never intended that the special rule apply in any other situation. By changing § 271.305(a), as noted, any ambiguity on this issue should be eliminated.

For a well drilled after December 31, 1978 and for which no drilling permit was issued until after that date, the special rule in § 271.305(b) requires that the jurisdictional agency make the requisite finding regarding effective and efficient draining of the proration unit "prior to the commencement of drilling" for this new well. Two comments contend that the finding should not be required to be made prior to the drilling of the new well. They contend that such a finding is not always possible before the drilling commences. One of these comments adds that there is no language in the NGPA which requires that the finding by the jurisdictional agency be made prior to the drilling.

Again, the Commission must take guidance from the Statement of the Conferees on the NGPA. In referring to situations where wells can be drilled within existing proration units and still qualify as new, onshore production wells, the Conferees stated that:

> In all cases, the unit must be designated prior to drilling the new well. S. Rep. No. 1126, 95th Cong., 2d Sess. 81 (1978).

This statement indicates the general intent of Congress that the need for the second well in a proration unit must be evaluated prior to drilling. However, because of the practical problems involved in determining—prior to drilling—if the new well is needed to effectively and efficiently drain the proration unit, the Commission will entertain applications by the jurisdictional agencies for alternative procedures that would allow such a finding to be made after the drilling and based on facts developed after the drilling. Accordingly, a new § 271.305(e) will be added to the special rule for new wells drilled in existing proration units to implement this procedure.

One problem identified by the comments is that establishment of proration units varies from State to State. For example, some States do not provide for proration units. In other States, a proration unit expires when the well on the unit is plugged and abandoned, and a new proration unit can be formed later when a new well is drilled in the same area. In yet other States, proration units exist indefinitely and independently of the well or wells within the unit. These diverse State policies regarding proration units conceivably could cause diverse results as the jurisdictional agencies make their determinations under section 103 of the NGPA.

The problem addressed by this comment is caused by the requirement in § 271.305(b)(2) that the requisite finding regarding the effective and efficient draining of an existing proration unit must involve either a redefinition of the boundaries of a proration unit or waiver of the applicable well-spacing requirements. Some States may be constricted by their proration unit and well-spacing policies and may not be able to redefine a proration unit or alter or waive a spacing requirement in conjunction with making the finding required by § 271.305(b). Such diverse results under section 103 could not have been intended by Congress. Accordingly, the Commission is removing the last sentence of § 271.305(b)(2) which currently requires a redefinition of the boundaries of a proration unit or alteration or waiver of applicable well-spacing requirements.

As a consequence, so-called replacement wells are now eligible to qualify as new, onshore production wells. Generally, replacement wells are wells drilled to replace another well in a proration unit when the other well is no longer capable of draining the reservoir covered by the unit because of geological or engineering reasons. Hence, the drilling of a replacement well usually does not necessitate a redefinition of the boundaries of the unit or a waiver of the applicable well-spacing rules. Thus, most replacement wells could not qualify as new, onshore production wells under § 271.305(b) of our interim regulations, which required either a change of an existing proration unit or an alteration or waiver of a spacing rule. Since § 271.305(b) is being amended to eliminate this requirement, replacement wells can now qualify as new, onshore production wells—as long as the requisite finding regarding the effective and efficient draining of the proration unit is made.

The Commission emphasizes that in order for any well drilled on an existing proration unit to qualify as a new, onshore production well, the jurisdictional agency still must explicitly find that the new well is necessary to effectively and efficiently drain a portion of the reservoir covered by the unit, which cannot be effectively and efficiently drained by any existing well on the unit. This requirement is the key to the special rule for wells drilled within existing proration units. To be able to review these findings more closely, the Commission will henceforth require that the explicit finding be based on appropriate geological and engineering data contained in the record submitted to the Commission by the jurisdictional agencies with their section 103 determinations. New language will be added to § 271.305(b)(2) and to § 274.204(f) (which establishes the pertinent filing procedures) to reflect the new requirement.

Also, the Commission takes note of the situation where the jurisdictional agency finds that both an existing well and the new well are necessary to effectively and efficiently drain a proration unit and a State has established allowables or production levels for that unit. The Commission is concerned that in this situation, the special rule in § 271.305 creates an incentive to produce a disproportionate amount of gas from the new well because it commands the higher price as a new, onshore production well. To prevent this result, the Commission will amend § 271.305(b)(2) to require the jurisdictional agency to provide a reasonable method of establishing separate allowables or production levels for each of the two wells. The allowables or production levels should be based on the respective ability of the two wells to deliver gas. In the cases where no State authority has established allowables or production levels for the proration unit, there is no need for an allocation of production from the two wells because the Commission assumes that both wells will produce in accordance with their respective abilities to deliver gas.

Several comments object to the fact that there is no mention in the interim regulations of the "local custom or practice" definition for proration units. Under section 2(8)(C) of the NGPA, when a proration unit is not specifically provided for by any State or Federal agency, it can be established by "local custom or practice". These comments contend that omission of the phrase "local custom or practice" from the regulations implementing section 103 of the NGPA indicates that formal State or Federal action will always be required by this Commission in order to establish a proration unit.

The Commission here points out that the definitions contained in the regulations implementing section 103, or any other section of the NGPA, are in addition to those definitions contained in the Act. See § 270.102(a) of our regulations. The Commission recognizes that a proration unit may be established in certain situations by "local custom or practice", but feels that promulgation in the final regulations of the definition in section 2(8)(C) of the NGPA is unnecessary.

For wells drilled on or after February 19, 1977 and before January 1, 1979, and for wells for which a drilling permit was issued before January 1, 1979, a transitional period rule is established in § 271.305(c). Under the transitional rule, the jurisdictional agency finding regarding effective and efficient draining of the proration unit does not have to be made prior to the drilling of the new well. The jurisdictional agency in making its finding can go back and review record evidence developed before the qualifying well was drilled. Two comments state that the transitional rule does not provide for the situation where the prior record was developed by an agency different from the jurisdictional agency that must make the section 103 determination. For example, for wells on Federal lands, a previous permit proceeding may have been conducted by a State agency, whereas under the NGPA the United States Geological Survey will have to make the jurisdictional determination for eligibility of the well under section 103. These comments assert that such wells may not be covered by the transitional period rule in § 271.305(c).

The concern expressed in these comments is well taken. The Commission will amend § 271.305(c) to make clear that where an agency other than the jurisdictional agency issued the drilling permit for the subject well, the jurisdictional agency making the required finding may rely on the record developed by the other agency.

One comment asserts that in New Mexico, for example, generally no records have been developed prior to the commencement of the drilling of wells, and that the State thus cannot review prior records as is necessary under the transitional rule. The comment suggests that the transitional rule be changed to allow an after-the-fact finding for such wells.

As noted on page 6, the Commission will entertain applications by jurisdictional agencies for alternative procedures that would allow such after-the-fact findings. A new § 271.305(e) has been added to the Commission's regulations to reflect this procedure. Thus, the problem raised by the comment can more appropriately be addressed by the Commission under the procedure set forth in § 271.305(e).

One jurisdictional agency suggests that the jurisdictional agencies be given the additional flexibility under §§ 271.305(b) and 271.305(c) to submit to this Commission the hearing record and order of the agency authorizing the drilling of the second well within an existing proration unit. The submission would be optional and would be made in lieu of the requirement of §§ 271.305(b) and 271.305(c) that the agency make the finding discussed above.

It would be administratively cumbersome for jurisdictional agencies to certify hearing records to this Commission. More importantly, the Commission is more concerned about the conclusions that a jurisdictional agency draws from the record it develops. If this Commission received just the record and the agency's order, we would be without the benefit of the relevant factual finding that the agency must make before a second well drilled on an existing proration unit can be determined to be a new, onshore production well. Without this explicit or implicit finding, required by §§ 271.305(b) or 271.305(c), regarding the effective and efficient draining of the proration unit, the Commission in its appellate role under the NGPA cannot make a meaningful determination whether the second well should qualify under section 103. Thus, this suggestion will not be adopted.

Another comment notes that the special rule of § 271.305 does not take into account wells which penetrate several reservoirs. This comment suggests that language be added to the special rule so that a well, which has penetrated several reservoirs and which is determined to be a new, onshore production well as to one reservoir, can automatically qualify as a new, onshore production well as to the other reservoirs. The comment requests that a separate finding by the jurisdictional agency prior to the drilling of the well not be required in order for the gas from each of the other reservoirs to be eligible for the section 103 price.

We recognize that multiple reservoir development can present practical problems involved in requiring separate findings by the jurisdictional agency prior to drilling. As noted previously, the Commission will under § 271.305(e) entertain applications of jurisdictional agencies for alternative procedures which would, if approved by the Commission, allow the findings to be made after drilling and based on facts developed after the drilling. The Commission points out, however, that in all cases where multiple reservoirs are penetrated by a single well a separate finding will have to be made for each reservoir covered by each proration unit.

Under § 271.305(d), the jurisdictional agency must notify the Commission if the agency makes the finding required by §§ 271.305(b) and 271.305(c). A comment suggests that a jurisdictional agency be allowed to file a blanket notification with the Commission when the agency makes such a finding for a field in which several wells are located.

Under § 274.207 of our interim regulations, a jurisdictional agency may submit for approval of the Commission alternative filing and notice requirements governing applications by producers for NGPA well determinations. Each jurisdictional agency is free to apply to the Commission for approval of an alternative plan incorporating a procedure for blanket notification as suggested. A party desiring such a blanket notification procedure as a means of complying with § 271.305(d) where there are several wells in a single field first must approach the pertinent jurisdictional agency. Only after a jurisdictional agency applies to the Commission for approval of such a blanket notification procedure will the Commission consider the merits of such a proposal.

One comment suggests that producers who file for a well determination under section 103 of the NGPA, not also be required to file for a certificate of public convenience and necessity under the Natural Gas Act for sales of gas made prior to a final section 103 determination. The comment contends that most of the gas involved will ultimately qualify for the section 103 price and that the certificate filing will therefore be unnecessary. The comment also contends that the certificate requirement will delay deliveries of gas to the interstate market while the producer awaits the issuance of the certificate from the Commission. This comment requests that the regulations make clear that filing for a certificate of public convenience and necessity is unnecessary for gas covered by section 103 pending the outcome of the jurisdictional agency proceeding and final review by the Commission.

Currently, the Commission is in the process of formulating a policy on the issue raised by this comment. Moreover, this issue which concerns the certificating of sales of committed or dedicated gas which ultimately may be excluded from the jurisdiction of the Commission under the Natural Gas Act, involves sections other than section 103 of the NGPA. Consequently, the Commission will resolve the issue in a separate order to be issued at a later date.

Under § 271.304 of the interim regulations, a new well is deemed to have satisfied applicable State or Federal well-spacing requirements if, prior to the commencement of drilling of the new well, a jurisdictional agency alters or waives the applicable well-spacing requirements. Two State public service commissions request that § 271.304 be amended so that the section does not include alterations and waivers granted for the sole purpose of having a new well qualify as a new, onshore production well. Otherwise, these State commissions allege, the requirement under section 103(c)(2) of the NGPA that a new well satisfy applicable well-spacing requirements would be rendered meaningless.

As noted above, the Commission believes that the special rule for new wells within existing proration units applies whenever a jurisdictional agency finds that a proration unit cannot be effectively and efficiently drained by an existing well, and that a new well is needed to perform the task. In some instances, to allow a new well that would qualify under the special rule as a new, onshore production well to be drilled on the existing proration unit, the jurisdictional agency must alter or waive its well-spacing requirements. Without § 271.304 as presently written, the jurisdictional agency in these instances would be foreclosed from determining that the new well is a new, onshore production well even though the agency makes the finding necessary for the well to qualify as such under the special rule. Furthermore, by permitting a State to waive its spacing requirements in order to permit new wells to qualify as new, onshore production wells, the Commission is not eviscerating section 103(c)(2) of the NGPA. The Commission does not believe that a State or Federal agency will necessarily waive its well-spacing requirements just to enable a well to qualify as a new, onshore production well. Thus, the request of these two State public service commissions must be denied.

One jurisdicational agency requests that § 271.304 be amended to provide a rule for changes in the sizes of proration units, similar to the rule for waivers of well-spacing requirements. Under the agency's proposal, when a jurisdictional agency redefines the boundaries of a proration unit prior to the drilling of a new well, which is within the former unit but which is also the only well within the newly created unit, the new well will be deemed to be not within an existing proration unit described in section 103(c)(3) of the NGPA.

The Commission must reject this proposal. Unlike waivers of well-spacing requirements for the purposes of section 103(c)(2) of the NGPA, redefinitions of the boundaries of proration units for the purposes of section 103(c)(3) must be accompanied by the finding regarding the effective and efficient draining of the existing proration unit. Unless the finding is made by the jurisdictional agency, a new well drilled within the former unit cannot qualify as a new, onshore production well, regardless of the fact that the new well is the only well within the newly created unit.

No comments were received by the Commission on §§ 271.301, 302 and 303 of our interim regulations. These sections have not been modified in the final regulations on new, onshore production wells issued by this order.

Finally, the Commission on its own motion makes certain other editorial changes in § 271.305. These changes do not reflect a variance in the Commission policy as implemented in the interim regulations.

Public Procedures and Effective Date

The regulations in Subpart C of Part 271 and Subpart B of Part 274 were originally proposed for comment in November of 1978 and issued as interim regulations on December 1, 1978 (43 FR 56448, December 1, 1978). For 60 days thereafter comments were received and during that period public hearings were held on these regulations. By this process the Commission complied with the provisions of section 502(b) of the NGPA which requires that "[t]o the maximum extent practicable, an opportunity for oral presentation of data, views, and arguments" be afforded for certain regulations under the NGPA.

The amendments to Parts 271 and 274 which are contained in this order rest upon consideration given to the information received during the above-described notice, comment, and hearing process, as well as upon comments received over the FERC "Hot Line." The Commission finds that further notice and public procedure with respect to these rules is unnecessary.

Subpart C of Part 271, as issued in final form, and Subpart B of Part 274, as amended,[1] relieve restrictions previously placed on producers who file applications under the interim regulations implementing the NGPA. Thus, the Commission is dispensing with the publication requirements of 5 U.S.C. 553(d)(1) (1977). Accordingly, both Subpart C of Part 271, issued as final regulations, and Subpart B of Part 274, as amended, are effective immediately with regard to jurisdictional agency determinations which have not yet become final under § 275.202 as of the day before the date of issuance of this order.

(Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.*; Department of Energy Organization Act, 42 U.S.C. 7107 *et seq.*, Exec. Order No. 12009, 42 FR 46267, Natural Gas Policy Act of 1978, Pub. L. No. 95-621, 92 Stat. 3350.)

In consideration of the foregoing, Subpart C of Part 271, Subchapter H, Chapter I, Title 18, Code of Federal Regulations, is issued as final regulations effective immediately as set forth above. Subpart B of Part 274 is amended effective immediately as set forth above.

By the Commission.

Kenneth F. Plumb,
Secretary.

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[1] There may be further amendments to Subpart B of Part 274 at the time Final Regulations for that Subpart are issued.

[¶ 30,079]

44 F. R. 49656 (August 24, 1979)

18 CFR Parts 271 and 274

[Docket No. RM79-73; Order No. 44]

Stripper Well Natural Gas; Final Regulations and Amendments to Interim Regulations

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Regulations and Amendments to Interim Regulations.

SUMMARY: The Federal Energy Regulatory Commission is issuing in final form regulations which implement section 108 of the Natural Gas Policy Act of 1978. Section 108 establishes ceiling prices and special rules for natural gas produced from stripper wells. The final regulations represent several modifications of the Interim Regulations issued December 1, 1978. In addition, the Commission is amending the requirements for filing with jurisdictional agencies for this type of gas to track changes made in the final regulations.

EFFECTIVE DATE: August 22, 1979.

FOR FURTHER INFORMATION CONTACT: Carol Lane, Office of the General Counsel, Federal Energy Regulatory Commission, Room 4208-F, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 275-4867.

Before Commissioners: Charles B. Curtis, Chairman; Georgiana Sheldon, Matthew Holden, Jr., and George R. Hall.

In the matter of final rule amending Subpart H of Part 271 on stripper well natural gas and amendments to § 274.206 of the interim regulations.

Issued: August 22, 1979.

I. Background

On December 1, 1978, the Federal Energy Regulatory Commission (Commission) issued interim regulations (43 FR 56448) implementing certain sections of the Natural Gas Policy Act of 1978 (92 Stat. 3350) (NGPA). Part 271, Subpart H, of the interim regulations implements section 108 of the NGPA, applying to first sales of natural gas produced from stripper wells. Subpart H contains definitions of terms used in section 108 and prescribes several special rules intended to assist in implementation of the section. Section 274.206 sets forth the filing requirements for stripper well natural gas determinations.[1]

II. Summary of Comments and Revisions to Subpart H

A. *General.* Section 108 of the NGPA prescribes a definition and a maximum lawful price for stripper well natural gas. According to the general rule prescribed in section 108(b)(1) of the statute, natural gas is stripper well natural gas if, during the 90-day production period preceding the date on which application is made for a stripper well determination, the well produced nonassociated natural gas at its maximum efficient rate of flow and did not exceed an average of 60 Mcf per production day. Natural gas may qualify as stripper well natural gas regardless of the spud date for the producing well. Section 108(b)(2) provides that a well may, after initial qualification, continue to qualify as a stripper well if production exceeds 60 Mcf per day during any 90-day production period, so long as the increased production is determined to have resulted from the application of recognized enhanced recovery techniques.

B. *Recognized Enhanced Recovery Techniques.* Section 271.803(a) of the regulations defines "recognized enhanced recovery techniques." In the interim regulations, this definition required that a recognized enhanced recovery technique increase the ultimate recovery of gas from a well. Comments from producers and jurisdictional agencies expressed confusion as to the meaning of the term "ultimate recovery." It was pointed out that it would be difficult to determine whether a well had actually experienced an increase in the amount of gas which could ultimately have been produced from the well had the enhanced recovery technique not been applied. Most comments asserted that the only determination which a jurisdictional agency could make with certainty would relate to whether or not rate of recovery from a well had been accelerated.

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[1] The amendments to § 274.206 are not being promulgated as final rules at this time. The Commission is considering promulgating all sections of Subpart B, Part 274, as final regulations by separate order.

Upon consideration of these comments, the Commission has concluded that our use of the term "ultimate recovery" established a test which was difficult to meet and which limited recognized enhanced recovery techniques to a narrower scope than was contemplated in section 108. We believe that once a well has qualified as a stripper well, Congress intended that a producer who applies an enhanced recovery technique which increases his rate of production above 60 Mcf per day should not be penalized by loss of the stripper well price. Accordingly, we have revised the rule to provide that any enhanced recovery techniques which increase the rate of production of gas from a well shall generally qualify as recognized enhanced recovery techniques. We have also revised the rule to provide that normal completion operations performed within two years of the initial completion do not qualify as recognized enhanced recovery techniques. This provision is intended to insure that a producer does not have an economic incentive to delay installation of a normal completion operation, establish the well as a stripper well, and then apply the completion operation, claiming that it is a recognized enhanced recovery technique. Additionally, the new rule provides that any drilling activity which results in production from another reservoir shall not qualify as a recognized enhanced recovery technique.

A number of comments asked that the Commission provide examples of processes or equipment that constitute recognized enhanced recovery techniques. Commentors gave particular attention to the issue of whether or not compression falls within the definition. In this respect, we believe it is clear from our revised definition that any technique shall qualify if it increases the rate of production from the well. Accordingly, compression qualifies as a recognized enhanced recovery technique so long as it is not a normal completion operation performed within two years of initial completion. With respect to what constitutes a "normal well completion operation," the Commission notes that such operations may differ from State to State due to geological differences in the producing reservoirs. For this reason we have stipulated in the regulation that the jurisdictional agency shall define the term "normal well completion operation" with respect to wells in the State. If the agency has not defined the term, it shall apply State custom or practice in making such determinations.

One comment suggested that determinations of what constitutes enhanced recovery techniques under § 271.803(a) should be left entirely to the jurisdictional agencies and not to the Commission. We do not agree. Section 501(a) gives the Commission authority to prescribe such rules as it finds necessary or appropriate to carry out its functions under the NGPA, and section 501(b) authorizes the Commission to define accounting, technical, and trade terms used in the Act. In the case of recognized enhanced recovery techniques, we have exercised our statutory authority to define this term because we believe that such a definition is essential to a reasonably uniform application of the provisions Congress included in section 108.

Another comment proposed that where a well qualifies as a stripper well for a 12-month period and then production increases to a level in excess of 60 Mcf per day, it should be conclusively presumed that the cause of this increase was the application of recognized enhanced recovery techniques. The Commission believes that adoption of this proposal would contravene the NGPA, because it would mean that once a well had maintained stripper status for 12 months it would conclusively maintain its stripper well status permanently. To the contrary, we note that the NGPA provides that maintenance of stripper status after production exceeds 60 Mcf per production day is specifically predicated upon the operator's having installed "recognized" enhanced recovery techniques.

C. *Nonassociated Natural Gas.* Section 271.803(b) defines "nonassociated natural gas." A well meets the statutory definition of a stripper well only if the gas it produces during the qualifying production period is not associated with oil. However, "nonassociated natural gas" is defined so as to permit a stripper well to qualify under this subpart if it produces crude oil in volumes which do not exceed specific limits. The rule provides for a sliding-scale ratio of natural gas to crude oil production, depending on the amount of production.

A number of comments addressed this issue. Some asserted that the definition went beyond the Commission's statutory authority and that "nonassociated natural gas" should properly be defined by the jurisdictional agencies. Others proposed that the sliding-scale crude oil allowance be eliminated because the statute makes no provision for it. On the other hand, some parties favored increasing the crude oil allowance, with a number of commentors favoring a 10-barrel-per-day limitation on crude oil production. Still others suggested that the sliding scale be replaced with a flat 3-barrel-per-day oil allowance in order to lessen administrative burdens and make the provision less restrictive.

As noted earlier, we have concluded that sections 501(a) and 501(b) of the NGPA provide authorization for the Commission, where appropriate, to define terms used in the Act. We believe that the definition of nonassociated natural gas established in the interim regulations conforms to the intent of Congress, as stated in the Statement of Managers, that "the Commission could allow a *de minimis* amount of oil to be produced from the well without disqualifying the well." (at p. 89) As we noted in the preamble to the interim regulations, we adopted the sliding scale in the belief that it provides a reasonable definition of nonassociated natural gas. Our approach is an attempt to reconcile two important interests which commentors on this section have stressed. First, we believe that a reasonable incentive is needed to preserve production of gas and oil from marginal wells, particularly in the Appalachian area. Too restrictive a limit on crude oil production could result in premature plugging and abandonment of marginal gas wells, which in turn could result in a permanent loss of reserves.

On the other hand, we are mindful that Congress provided in section 108(b)(3)(c) of the NGPA that nonassociated natural gas means natural gas which is not produced in association with crude oil.

While the above-cited Statement of Managers and other legislative history make it clear that Congress intended a minimal amount of crude oil production to be permitted, we feel constrained to keep crude oil allowances to a *de minimis* standard. Accordingly, we believe that the definition as it stands is reasonable and prescribes limits contemplated by Congress.

In addition, the Commission's sliding scale approach is predicated in part on the economics of producing both oil and gas from marginal wells. We believe that aggregate revenues from such wells should be adequate to maintain continued production. However, such aggregate revenues should not exceed those revenues which would result from the sale of 60 Mcf of gas and 1 barrel of oil. The sliding scale in § 271.803(b) implements this approach.[3]

D. *90-Day Production Period and Production Day.* Two additional definitions have been added to § 271.803 in response to comments which asked that the statutory terms "90-day production period" and "production day" be explained in our regulations. A new subparagraph (c) defines that former term, and a new subparagraph (d) defines the latter. Both reflect the statutory definitions. Subpart (c) also establishes a presumption (explained below) with respect to the establishment of a 90-day production period.

A 90-day production period is defined as any period of 90 consecutive calendar days, excluding those days during which natural gas is not produced for reasons other than voluntary action of any person with the right to control production. All stripper well determinations rest on qualifying 90-day production periods. The Commission has determined, however, that several important administrative considerations make it appropriate that 90-day production periods be calculated on a 90-calendar-day basis, without bringing additional days into the period in cases where some days are excluded pursuant to the statutory definition. We note two relevant considerations in this respect. First, it is general industry practice to keep production records on a monthly rather than daily basis. Any necessity to change this practice could present producers with a difficult and costly burden. Second, the calculations required to compute a statutory 90-day production period would complicate the jurisdictional agency determination process while resulting in no substantial difference in the outcome of the determination in the great majority of cases.

Accordingly, the Commission has determined that where average daily production, calculated on a 90-calendar-day basis, is 60 Mcf or less per production day, there is substantial evidence to support a finding that the well produced 60 Mcf or less per production day during the 90-day production period defined in the statute. To implement our determination in this respect, we have provided in § 271.803(c)(2) that where records for a 90-consecutive-calendar-day period indicate that the well produced 60 Mcf or less per production day during that period, a rebuttable presumption is created that the well produced 60 Mcf or less per production day during the statutory 90-day production period.

A "production day" is defined in § 271.803(d) as (1) any day during which natural gas is produced, and (2) any day during which natural gas is not produced if production during such day is prohibited by a requirement of State law or a conservation practice recognized or approved by the State agency having regulatory jurisdiction over the production of natural gas.

Under these regulations, we will permit a 90-day production period to be calculated as follows:

(1) The producer shall submit daily or monthly production records for a 90-consecutive-calendar-day period.

(2) The producer shall submit the number of days natural gas was produced during the 90-consecutive-calendar-day period.

(3) The producer shall submit, if applicable, the number of days natural gas was not produced during the 90-consecutive-calendar-day period, and (a) a description of the State law or conservation practice (recognized or approved by the State agency having regulatory jurisdiction over the production of natural gas) under which the well did not produce on any such day or days, or (b) and explanation of any other reason the well did not produce on any such day or days.

(4) The total volume of gas produced during the 90-consecutive-calendar-day period shall be divided by the number of

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[3] For example, if a well produced 30 Mcf of gas (at $2.50 per Mcf) and 3 barrels of oil (at $20 a barrel) per day, aggregate revenues from the well would be $75 + $60, or $135 per day. These aggregate revenues would not exceed aggregate revenues for a well producing 60 Mcf of gas and 1 barrel of oil per day ($150 + $20, or $170 per day).

days in the period which qualify as "production days" as defined in § 271.803(d). The figure reached is to be rounded off to the nearest whole number. Fractions are rounded off by increasing the whole number where the fraction is equal to or greater than .5 Mcf (e.g., 60.6 Mcf = 61 Mcf) and by dropping any fraction less than .5 Mcf (e.g., 60.4 Mcf = 60 Mcf).

(5) Where the average production, calculated according to (4) above, is 60 Mcf or less per production day, a presumption is created that the well produced 60 Mcf or less per production day during the statutory 90-day production period.

(6) The presumption created according to (5) above may be rebutted by the purchaser or other interested person by evidence showing that if the producer, pursuant to the statutory definition of 90-day production period, had excluded days during which natural gas was not produced for reasons other than voluntary action, and subsequently added on days to bring the production period back to a total of 90 calendar days, production for that period would have exceeded 60 Mcf per production day.

Sections 274.206(a)(4) and (5) have been amended, where appropriate, to accord with the above-described procedure.

The Commission is also aware that some three-calendar-month records may contain slightly more or less than 90 calendar days. For example, the period February–March–April 1979 contained 89 calendar days. In such cases, we believe that reasonable assumptions premised upon monthly records will provide the jurisdictional agency with sufficient evidence upon which a determination may be made.

E. *Rate of Production.* Section 271.804 sets forth special rules which interpret and apply terms used in the NGPA. Section 271.804(a) concerns the methodology for determining the rate of production from a well for which a stripper well determination is sought. Comments were received from a number of producers, as well as from the State of New Mexico and one of its Senators, proposing that the Commission revise this interim rule. The commentors objected to the requirement that total volume of natural gas produced from the well be utilized for purposes of calculating the average rate of production, regardless of whether the well is completed in more than one interval. It was suggested that separate completion locations within a multi-completion well be treated as separate wells for purposes of determining rate of production. The parties argued that the rule as it stood would encourage owners to refrain from producing a second reservoir within the same bore because this might mean loss of the stripper price. They argued further that owners might also be encouraged to plug one interval of a well in order to qualify production from another interval as a stripper. Some parties made the point that dual completions may have nothing in common other than the same wellbore: they may have different interest owners, different royalty owners, different purchasers, and fall into different price categories. Other comments noted that many States and Government agencies have traditionally classified individual completions as individual wells and that nothing in the NGPA directly contravenes this traditional practice.

The Commission cannot agree that a practice should be maintained solely because it is traditional, or that the interests of different owners or purchasers in the same wellbore make the interim rule unreasonable. We recognize that there may be cases in which treating volume from separate intervals as total volume in order to calculate stripper well eligibility may result in a lack of incentive to drill a new interval or to maintain an old one. However, we believe that the language of the statute supports the Rate of Production rule. We note that Congress provided separate definitions for the terms "well" and "completion location" in section 2 of the NGPA. Throughout the Act, Congress made use of the term "completion location" in places in which that term needed to be distinguished from the term "well." For example, in sections 102, 103, and 107, Congress referred to "completion location" when describing certain criteria under which wells could qualify under those sections. But Congress did not use the term "completion location" when describing criteria for qualification under section 108. We believe that if Congress had intended stripper well qualification to be determined for each "completion location," it would have used that term. Congress instead used the term "well."

Accordingly, we believe that the Rate of Production rule implements Congressional intent that total volume from the well, regardless of whether it is completed in more than one interval, is the basis for calculation of volume under section 108.

Another comment on § 271.804(a) requested that the Commission make it clear that rate of production may be measured either before or after the extraction of natural gas liquids. In this respect, we note that the Statement of Managers says: "The 60 Mcf per day measurement is intended to be applied after extraction of natural gas liquids; production of natural gas liquids does not disqualify a well from qualifying as a natural gas stripper well" (at p. 89). Accordingly, § 271.804(a) has been amended to reflect this Congressional intent.

F. *Averaging of Production.* Section 271.804(b) applies when the wells are not individually metered. Under paragraph (b), jurisdictional agencies may average rates of production in order to determine whether particular wells are stripper wells. For example, if six wells were attached to a single meter, and the meter showed deliveries averaging 360 Mcf per production day, presumptively all wells would qualify. If, on the other hand, deliveries from the six wells averaged 370 Mcf per production day, presumptively none of the wells would qualify. In either case, alternative evidence may be offered in rebuttal to establish qualification or the lack of qualification.

One comment on this rule suggested that an allocation to each well should be calculated based on both a master meter reading and periodic production tests of each well. We do not believe that periodic tests on individual wells are necessary in order to insure stripper well eligibility where there is a single meter. Accordingly, the interim rule has not been changed.

G. *Applications for Determinations.* Section 271.804(c) originally provided that an application for a stripper well determination be based on a 90-day production period falling within 120 days of the date on which the application was filed. Inquiries made over the FERC "Hot Line" indicated that some parties interpreted this rule to mean that any 90-day production period in which one or more days fell within 120 days of the filing date would qualify under the rule. It was not the Commission's intent to allow such a prolonged interval between the end of the 90-day production period and the date of filing. We believe that a jurisdictional agency should be provided with the most current data possible upon which to make a stripper well determination. Accordingly, we have revised the rule to make it clear that the *entire* 90-day production period must fall within the prescribed period for filing. However, in response to one written comment, we have also expanded the 120-day limit to 180 days. This will give an owner or operator a maximum of 90 days after the end of the 90-day production period within which to file a stripper well application. (Section 271.805(c) has also been changed to allow a maximum of 90 days for filing a notice of increased production pursuant to the rules for continuing qualification.) Section 274.206, which sets forth the filing requirements for stripper well determinations, is also amended, in § 274.206(a)(3)(ii), to reflect both of these changes.

A group of producers proposed that any well which had a documented history as a stripper well before May 1, 1978 but whose production subsequently rose above the 60 Mcf limit as the result of the application of recognized enhanced recovery techniques should be eligible to apply for a stripper well determination. The Commission disagrees. The definition of stripper well natural gas in section 108(b)(1) requires the establishment of a 90-day production period (during which production did not exceed an average of 60 Mcf per day) preceding the application for a stripper well determination. The statutory definition then goes on to provide that a well "which previously qualified as a stripper well under paragraph (1)" may exceed the 60 Mcf per day limit if the increase was the result of application of a recognized enhanced recovery technique. Accordingly, in order for a well to be eligible for a determination that production has increased due to a recognized enhanced recovery technique, an applicant must *first* have established a qualifying preceding 90-day production period. A well such as that described in this comment cannot establish such a qualifying period.

H. *Seasonally-affected Wells.* Section 271.804(d) (formerly § 271.804(e)) is a special rule which permits wells to retain stripper status despite increases in production above the 60 Mcf per day level, provided the increase is attributable to seasonal fluctuations. Jurisdictional agencies may make the determination that a well is seasonally affected on the basis of production history over a 24-month period if production from the well has not and cannot reasonably be expected to have exceeded an average of 60 Mcf per day for any 12-month period.

Comments from State public service commissions and other groups recommended that this special rule be deleted, because section 108 does not provide a statutory predicate for it. The Commission disagrees. Production from a well often varies as a result of pressure differentials. A rule that ignores this occurrence would place an undue administrative burden on producers, States and the Commission. Many wells would have to go through the qualification and disqualification process every year. The Commission believes that once a well has qualified as a stripper, it should be able to remain qualified as long as production, when calculated on a yearly basis, does not exceed an average of 60 Mcf per production day, where the well is determined to be seasonally affected. The Commission believes this rule is practical, is within the spirit and intent of the law, and is a proper exercise of its rulemaking authority under section 501(a) of the Act.

One comment on seasonally affected wells asked if production level, as set forth in § 271.804(d)(1), was the only criterion for the establishment of a well as a stripper well. This party pointed out that the filing requirements of § 274.206(d)(4) additionally require that an applicant describe "the nature of the seasonal fluctuations." In this respect, the Commission notes that § 271.804(d)(1) provides that a designation that a well is seasonally affected shall be granted by a jurisdictional agency "only if it finds that the seasonal fluctuations have not and cannot reasonably be expected to increase production levels above an average of 60 Mcf per production day for any 12-month period." We believe that a jurisdictional agency must look into the nature of seasonal fluctuations in order to make such a finding. Accordingly, the filing requirement of § 274.206(d)(4) acts as a supplement to the special rule for seasonally affected wells.

Section 274.206(d)(5) requires that the applicant file a statement indicating that notice of the designation that a well is seasonally affected has been served on the entities listed in § 271.805. Section 274.206(d)(5) is amended to clarify that notice is required to be served on the jurisdictional agency, the Commission, and any purchaser. A similar change is made in § 274.206(c)(4).

Section 271.804(d)(1) also requires that production records for a period of at least 24 months accompany a petition for a designation as a seasonally affected well. One jurisdictional agency proposed that the 24 months be reduced to 12 months, arguing that seasonal variations on gas wells generally show their range over a 12-month period. We decline to make this change. It is our belief that a 24-month record provides a more reliable indication of a well's true production pattern.

Section 271.804(d)(3) of the interim regulations contained a clerical error which has been corrected in the final regulations. This section now exempts the purchaser and operator of a well which has been designated as seasonally affected from the filing requirements of § 271.805 (not § 274.805), unless the average rate of production exceeds 60 Mcf per day for a 12-month period.

I. *Continuing Qualification.* Section 271.805 is a rule implementing section 108(b)(2) of the NGPA. The format of the section has undergone certain revisions for purposes of clarification.

The continuing qualification rule disqualifies wells which produce quantities of gas in excess of the amounts permitted by law and this subpart. The rule also provides for a reporting mechanism to monitor the continued qualification of the well. Both the operator of the well and the purchaser of the gas are obligated to report any increase in gas production above an average of 60 Mcf per production day for any 90-day production period. Unless the operator receives a determination from a jurisdictional agency that the increase was due to the application of recognized enhanced recovery techniques, or that the well has been designated as seasonally affected, he may no longer collect the stripper price for the well. If the operator files a petition for a determination that the increase results from enhanced recovery techniques or seasonal fluctuations, or if he files a motion contesting the notice, continued collection of the stripper well price shall be made subject to refund for deliveries made after the last day of the applicable 90-day or 12-month production period.

One comment proposed that a jurisdictional agency be permitted to make a permanent finding that a well is seasonally affected, excusing the operator and purchaser from any further filing requirements under this section, regardless of subsequent production level. The Commission has not adopted this approach. A properly designated seasonally affected well which subsequently exceeds the allowable 12-month production level for reasons other than use of recognized enhanced recovery techniques can no longer be defined as a stripper well under section 108(b)(1) of the NGPA. We believe that to ignore production level once a well is designated as seasonally affected is to ignore our duty to administer and enforce the NGPA.

Another comment on § 271.805 proposed that the section be eliminated altogether, adopting an approach of "once a stripper, always a stripper." As noted previously, the Commission believes that the implementation of sections 108(b)(1) and 108(b)(2) requires the rule. We have attempted in § 271.805(d) to give operators a reasonable means of challenging any notice given by a purchaser that the statutory limit has been exceeded. Section 271.805(d) provides that a well will not lose its stripper well status if a petition opposing the notice is filed within 30 days of the date the purchaser gives notice. The operator may continue to collect the maximum lawful price, subject to refund from the last day of the 90-day or 12-month production period described in the notice.

A number of comments from pipelines proposed that the burden of giving notice under § 271.805(a) be placed solely on the operator, rather than on both operator and purchaser. It was argued that the operator is in the best position to determine when the well exceeds stripper limits. The Commission strongly disagrees with this proposal. We find that to require a pipeline to monitor its purchases of stripper well gas is not unduly burdensome. In many cases the pipeline already monitors production for purposes of billing. More importantly, however, we believe that our rule is consistent with the duty pipelines owe to their own purchasers to insure that all gas purchases are properly priced.

Two comments asserted that § 271.805 should require that written notice be given if production of crude oil exceeds the amount allowed under the definition of nonassociated natural gas. The Commission has not adopted this proposal because of our concern about both the practical difficulties inherent in monitoring oil production and the administrative burden it would impose. In a situation where oil production increases, we believe that as a general matter gas production will also increase. Consequently, most wells which come to exceed the oil limit will at the same time exceed the gas limit and be disqualified as strippers on the basis of the latter. Should a situation come to the Commission's attention wherein this general proposition does not apply and wherein crude oil production is in excess of the prescribed limits of § 271.803(b), the Commission will undertake whatever measures we deem appropriate to resolve the matter.

J. *Jurisdictional Agency Determinations and Commission Review.* Section 271.806(a) stipulates that upon receipt of a petition to designate a well as seasonally affected or an application to determine that production in excess of the stripper well limitation was due to use of recognized enhanced recovery techniques, the jurisdictional agency shall treat the petition or application as if it were an application for an initial determination. Section 271.806(b) provides for Commission review of juridsdictional agency determinations with respect to seasonally affected wells and recognized enhanced recovery techniques.

In order to assist jurisdictional agencies in making determinations with respect to enhanced recovery techniques, § 271.806(c) provides that an agency may seek a declaratory order or staff interpretation from the Commission that a type of process or equipment qualifies as a recognized enhanced recovery technique as defined in § 271.803(a). In this respect one commentor asked whether the declaratory order procedure was optional or mandatory on the part of a jurisdictional agency. We stress that initial determinations regarding recognized enhanced recovery techniques will be made by each jurisdictional agency pursuant to the definition established by the Commission in § 271.803(a) and subject to Commission review. The declaratory order procedure is available to an agency, on an optional basis, in order to facilitate its determinations.

Another comment asked that the Commission specify the procedure to be employed when an agency seeks a declaratory order with respect to recognized enhanced recovery techniques. Accordingly, we have added language to § 271.806(c) to provide that such declaratory orders shall be filed in accordance with the requirements of § 1.7(c) of the Commission's Rules of Practice and Procedure (18 CFR 1.7(c)).

A group of producers suggested that it would be helpful if a producer could directly file with the Commission for a declaratory order on a particular enhanced recovery technique. It was argued that producers will be reluctant to install certain techniques without advance knowledge that the well will retain its stripper well status. The Commission notes that under § 1.7(c) of its Regulations any person may file for a declaratory order on an issue in which that person has an interest. Section 271.806(c) was specifically included in our regulations so as to emphasize that jurisdictional agencies may seek declaratory orders with respect to recognized enhanced recovery techniques. The Commission contemplates that each jurisdictional agency will make the initial determination on this issue, basing its decision on our definition of the term.

We have also provided, in an amendment to § 271.806(c), that a jurisdictional agency may seek a staff interpretation from the Commission with respect to a recognized enhanced recovery technique. We encourage agencies to seek such interpretations where necessary to facilitate their decisions.

A suggestion was made that a well producing low Btu gas should be allowed to exceed the 60 Mcf per day limit, yet still qualify as a stripper. The Commission declines to make such an allowance because the NGPA clearly stipulates that stripper well production shall be measured in Mcfs. Btu content is a consideration only for purposes of determining the maximum lawful price.

K. *Maximum Efficient Rate of Flow.* Section 108(b)(1)(B) of the NGPA provides that a well must produce at its "maximum efficient rate of flow" (MER) during the 90-day production period in order to qualify as a stripper well. Section 271.807 (formerly § 271.804(d)) implements this MER requirement. The section has been amended in several respects, as discussed below, and conforming amendments have been made in § 274.206.

Section 271.807(a) applies the statutory requirement for establishment of MER and § 271.807(b) provides alternative methods for establishment of MER. The first alternative provides that if a well has produced an average volume of 60 Mcf or less per production day during the 12-month period ending concurrently with the 90-day production period, there is a rebuttable presumption that the well produced at its MER during the 90-day production period. The Commission notes that over the course of the 12-month period a well may occasionally be shut in for several days or weeks as part of normal production procedure. Such a shut-in will not disqualify the well from establishing MER. We wish to make it clear, however, that a well which is not producing at all during the 9 months preceding the 90-day production period cannot be presumed to have produced at its MER during the 90-day production period. An MER presumption cannot reasonably be made unless the jurisdictional agency is able to review a record which sets forth the production pattern and rate of production over a 12-month period during which the well was actually in production.

The second alternative method of establishing MER involves situations in which natural field decline has brought about a gradual decrease in a well's production to a point at which the well is producing 60 Mcf or less during the 90-day production period, but where production during the preceding 9 months was high enough that the well's 12-month production average slightly exceeded 60 Mcf. The Commission is adopting a new regulation to apply in this situation. Section 271.807(b)(1)(ii) provides that where a well's production during the 12 months ending concurrently with the 90-day production period indicates an average of 70 Mcf or less per production day, the jurisdictional agency shall defer making a determination on the well and shall establish a later 12-month period upon which to determine MER. (This deferred 12-month period must include the 90-day production period upon which the application was based.) At the end of the deferred period, the applicant shall submit the relevant production records and the jurisdictional agency shall determine whether or not the well's average production for the deferred 12 months exceeded 60 Mcf. The agency shall then make the MER determination accordingly. An applicant may make interim collection of the section 108 price during the period of deferral, or may collect such price retroactively once an affirmative determination has become final.

The Commission's decision to amend the regulations in this regard rests on our confidence that examination of a well's production history can provide the jurisdictional agency with substantial evidence that a well has or has not met the statutory requirement with respect to MER. We have established a 12-month average production level of 70 Mcf as a cut-off point for permitting deferral of the determination because we believe a well within the 61–70 Mcf range per production day during that period may experience natural decline to 60 Mcf or less per production day by the last 90 days of that 12 month period. If, however, average production at 60 Mcf or less is not experienced during a deferred 12-month period, the jurisdictional agency must make a negative determination and the applicant must make the appropriate refunds pursuant to the provisions of Subpart C of Part 273.

There may arise situations in which a 12-month production history is not available because the well is new. In such situations, the jurisdictional agency may also employ the deferral process described above.

A final alternative method of establishing MER is provided in § 271.807(b)(3). The jurisdictional agency may base the determination on other substantial evidence, such as flow tests, which measure production capability.

Unless the jurisdictional agency is relying on § 271.807(a) or § 271.807(b)(3), it is required to make a negative determination in the following situations:

(1) Where production data for the 12 months ending concurrently with the 90-day production period indicate that the well's average production exceeded 70 Mcf;

(2) Where production data for the deferred 12 month period indicate that the well's average production exceeded 60 Mcf; and

(3) Where the jurisdictional agency is relying on a deferred 12 month period and the applicant fails to submit the required production data.

In order to clarify the MER regulations, the Commission has amended § 271.807 to eliminate the word "nonassociated" from portions of the section and from portions of the filing requirements of § 274.206. This change has been made because the phrase "nonassociated natural gas" refers to the kind of gas which must be produced during a 90-day production period. We do not believe it is appropriate to extend this phrase to apply to one of the tests used to establish MER.

One comment on this section expressed concern that the Commission's regulations exceed its statutory power because they dictate procedures under which a jurisdictional agency shall make determinations as to MER. The Commission wishes to stress that § 271.807(a) provides that a jurisdictional agency may establish its own procedures, in accordance with recognized conservation practices, for determining maximum efficient rate of flow. In a case where such procedures have not been established by the agency, § 274.807(b) sets forth what the Commission considers reasonable data upon which to determine MER.

Section 271.807(c) provides that an applicant who is required by the jurisdictional agency to submit deferred 12-month production data has 90 (rather than 30) days from the end of the 12-month period to submit the data to the agency. This change is made in response to a comment which pointed out that gas purchasers often take more than 30 days to supply meter statements to gas sellers.

III. Public Procedures and Effective Date

The regulations in Subpart H were originally proposed for comment in November of 1978 and issued as interim regulations on December 1, 1978 (43 FR 56448, Dec. 1, 1978). For 60 days thereafter comments were received and during that period public hearings were held on these regulations. By this process the Commission complied with the provisions of section 502(b) of the NGPA, which requires that, "(t)o the maximum extent practicable," an opportunity for the oral presentation of data, views, and arguments be afforded for certain regulations under the NGPA.

The amendments to Subpart H contained in this order rest upon consideration given to the information received during the above-described notice, comment, and hearing process, as well as upon comments received via the FERC "Hot Line." The Commission finds that further notice and public procedure with respect to Subpart H is unnecessary.

Subpart H of Part 271, as issued in final form, and Subpart B of Part 274, as

amended,[3] relieve restrictions previously placed on applicants under the interim regulations, with two exceptions. Thus the Commission is dispensing with the publication requirements of 5 U.S.C. 553(d)(3), except with respect to §§ 271.804(c), and 271.807. Accordingly, both Subpart H of Part 271, issued as final regulations, and Subpart B of Part 274, as amended, are effective immediately with regard to jurisdictional agency determinations which have not yet become final under § 275.202 as of the day before the date of issuance of this order, except that §§ 271.804(c) and 271.807 are effective 30 days from date of issuance with regard to applications for determinations filed on or after date of issuance.

(Natural Gas Policy Act of 1978, Pub. L. 95–621, 92 Stat. 3350, Department of Energy Organization Act, 42 U.S.C. 7107 *et seq*, EO 12009, 42 FR 46267.)

In consideration of the foregoing, Subpart H of Part 271, Subchapter H, Chapter I, Title 18, Code of Federal Regulations, is issued as final regulations effective immediately as set forth above, except that §§ 271.804(c) and 271.807 are effective 30 days from date of issuance. Subpart B of Part 274 is amended, effective immediately as set forth above.

By the Commission. Commissioner Hall was present and not voting.

Kenneth F. Plumb,
Secretary.

[¶ 30,080]

44 F. R. 51554 (September 4, 1979)

18 CFR Parts 2, 271

[Docket No. RM 79-19; Order No. 45]

Treatment of Certain Production-Related Costs for Natural Gas to be Sold and Transported Through the Alaska Natural Gas Transportation System; Statement of Policy

August 24, 1979.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Regulations and Statement of Policy.

SUMMARY: The Federal Energy Regulatory Commission (the Commission hereby gives notice of an amendment to Part 271, Subchapter H of its interim regulations promulgated under the Natural Gas Policy Act of 1978 (NGPA). The amendment permits those involved in the first sale of natural gas produced from Prudhoe Bay, Alaska for transportation through the Alaska Natural Gas Transportation System (ANGTS) to apply for an allowance under section 110 of the NGPA for costs incurred in removing carbon dioxide from levels of three percent by volume to levels below three percent by volume and to apply for adjustments pursuant to section 501(c) of the NGPA in the event of special hardship, inequity, or an unfair distribution of burdens. The Commission also gives notice of promulgation of a statement of policy under the Natural Gas Act that there will be a rebuttable presumption that costs incurred by shippers or transporters to condition natural gas produced at Prudhoe Bay, Alaska for transport through the ANGTS are imprudently incurred. This policy would not apply to costs permitted first sellers under Part 271, subpart K of Commission regulations or those incurred to reduce carbon dioxide content from three percent to below three percent by volume. In issuing this rule and policy, the Commission provides that the rule and policy will not be effective for 60 days and for petitions for rehearing to be filed within 30 days of the issuance of the rule and policy. The Commission

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[3] **There may be further amendments to Subpart B of Part 274 at the time Final Regulations for that Subpart are issued.**

also provides for the oral presentations of views on the rule issued.

DATES: Effective date October 23, 1979; petitions for rehearing, September 24, 1979; oral presentations, to be announced.

ADDRESSES: All petitions should reference Docket No. RM79-19 and should be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: John Adger, Director, Alaska Natural Gas Project Office, Federal Energy Regulatory Commission, 941 North Capitol Street, NE., Washington, D.C. 20426 (202) 275-3827.

The Federal Energy Regulatory Commission (Commission) by this rule establishes responsibility for bearing costs of conditioning natural gas produced from the Prudhoe Bay Unit in Alaska for transport through the Alaska Natural Gas Transportation System (ANGTS). The responsibility is apportioned between producers of Prudhoe Bay natural gas and the shippers, transporters and ultimate consumers of that gas. To this end the Commission amends its interim regulations implementing section 110 of the Natural Gas Policy Act of 1978 (NGPA) to permit first sellers of natural gas produced for the ANGTS to make application for recovery of costs incurred in removing carbon dioxide from levels of three percent by volume to levels below three percent by volume. The Commission, coincident with this rule, issues a policy statement addressing the recovery of certain production-related costs incurred by transporters and shippers of natural gas produced at Prudhoe Bay; recovery of such costs will be comparably limited to carbon dioxide removal below three percent by volume.

A. Background

1. *ANGTS and the President's Decision.* In 1968 the largest single discovery of oil and gas ever made on the continent of North America was made at Prudhoe Bay on the North Slope of Alaska. The oil is currently flowing, but the associated gas cannot be marketed until a transporting gas pipeline is built. Virtually every estimate exceeds 26 trillion cubic feet of proven recoverable gas reserves at Prudhoe Bay. This large deposit of natural gas could supply more than two billion cubic feet of natural gas per day (approximately five percent of the nation's current requirements) over a 25-year period.

In recognition of the importance of this domestic energy source, the Congress passed the Alaska Natural Gas Transportation Act of 1976 (ANGTA), 15 U.S.C. 719 *et seq.* By this Act, the Congress established a procedural framework to expedite a final decision on and implementation of an ANGTS. That framework included a procedure to select a system. It also included specific provisions for the prompt handling of all federal authorizations necessary or related to the construction and initial operation of that system, and limited judicial review of agency action to approve authorizations for that system.[1]

In September of 1977, the President sent to the Congress his finding that the Alcan Pipeline Company, because its proposal was economically and environmentally superior to competing proposals, should be granted the certificate to construct the ANGTS.[2] The

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[1] 15 U.S.C. 719, c, d, e, f, g, and h. The judicial review is limited to questions of agency violation of constitutional or statutory law. *See Midwestern Gas Transmission* v. *FERC*, 589 F. 2d 603, 625–626 (D.C. Cir. 1978).

[2] Executive Office of the President, Energy Policy and Planning, *Decision and Report to Congress on the Alaska Natural Gas Transportation System* (September, 1977) [hereinafter cited as *Decision*]. The present sponsors for the Alaskan segment are the successors to the Alcan Pipeline Company; see "Order Transferring Conditional Certificate of Public Convenience and Necessity from Alcan Pipeline Company to Alaskan Northwest Natural Gas Transportation Company, Reviewing Relevant Portions of Underlying Partnership Agreement and Granting Intervention" (Docket No. CP78-123, *et al.*) (June 30, 1978).

Congress, by joint resolution, approved and adopted the President's *Decision* in November of that year. H.J. Res. 621, Pub. L. No. 95–158, 91 Stat. 1268 (1977).

The ANGTS, the system approved in the *Decision*, will be 4,800 miles in length, originating on the North Slope of Alaska and passing through Canada to the lower-48 states. At the time of the President's *Decision* the capital costs of this transportation system were estimated at $10.5 to $13.9 billion,[3] which would make the project the largest privately financed project in history.

The *Decision* specifically identified the facilities which would comprise the ANGTS. These facilities constitute the "approved transportation system" within the provisions of section 7(a)(4) of ANGTA, 15 U.S.C. 719e(a)(4). Under the *Decision* the approved transportation system does not include the facilities which will prepare the Prudhoe Bay gas for entry into the pipeline. In Section 2 ("Description of the Nature and Route of the Approved System"), the *Decision* states: "The proposed Alcan pipeline will commence on the discharge side of the gas conditioning plant facilities in the Prudhoe Bay Field."[4] The *Decision* also states that "[t]he facilities which are to be covered are those in the U.S. which * * * are included in the revised Alcan filing submitted to the Federal Power Commission (FPC) in March 8, 1977."[5] That filing assumes facilities which would accept gas conditioned to a certain quality, and compressed and chilled prior to entry.[6]

The *Decision* did not resolve one particular issue which is important to the implementation of the selected system, the establishment of a field price for the gas.

The importance of this gap was described in the *Decision*.

> Final financing for an Alaskan natural gas transportation project cannot be arranged until the producer-owners of the Prudhoe Bay gas execute sales contracts. Without such contracts, no gas can be transported, and financing consequently would be unobtainable. Producers cannot be expected to negotiate sales contracts until a price has been established with a reasonable degree of certainty. If this project is to proceed expeditiously, the field price of the gas should be established as soon as possible. (*Decision* at 44.)

The Commission, in its comments on the *Decision*, acknowledged its jurisdictional responsibility to determine the appropriate field price.[7]

> In addition to tariff and financing issues, a wellhead rate for producer sales must be set either by the Congress through amendment to the Natural Gas Act or, failing that, by FERC. The costs of separating and processing the casing head gas must be identified and allocated. (FERC Comments at 4.)

The Commission went on to discuss the various types of costs involved in producing the gas and preparing it for pipeline entry (FERC Comments at 19–34), but observed that the *Decision* called for enactment of a gas pricing approach for the ANGTS similar to that contained in the Administration's National Energy Plan, then under consideration by the Congress.[8]

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[3] *Decision* at 157.

[4] *Id.* at 6. Additionally, the system description in Section 3 of the *Decision* states that the first compressor station and attendant chilling facility for the ANGTS will be located 75 miles after the point of commencement of the system. *Id.* at 17.

[5] *Id.* at 13.

[6] Alcan Pipeline Project 48" Alternative Proposal, Docket No. RM77–6. The revised Alcan filing describes a system which would transport natural gas processed to the following standards: (1) 1% carbon dioxide by volume; (2) 0.6% nitrogen by volume; (3) 1138 Btu/cu. ft. gross heating value; and (4) a hydrocarbon dew point of −10 degrees F at 1000 psi. (Alcan Pipeline Project 48" Alternative Proposal at § 2, p. 3; Docket No. RM77–6). This revised filing referenced an initial filing in which the following additional specifications were enumerated: (1) a maximum water content of 0.2 pounds per million cubic feet; (2) a sulphide content of no more than 0.25 grains per 100 cubic feet; and (3) a total sulphur content of no more than 10 grains per 100 cubic feet. Alcan Pipeline Co., FPC Gas Tariff, Original Vol. 1, Exhibit No. AP–16, at Original Sheet No. 112 (Docket No. CP75–96, *et al.*).

[7] Federal Energy Regulatory Commission, *Comments on the Decision and Report to Congress on the Alaska Natural Gas Transportation System* (October, 1977) [hereinafter cited as FERC Comments].

The Report which accompanied the *Decision* contained a discussion of the economic viability of the ANGTS.[9] Because of the possibility that the Commission might provide some allowance for costs of gathering, conditioning, and compression, that discussion used a range of 0 to 30 cents per MMBtu (1975 dollars) for a potential add-on for such costs in estimating the "city gate" or wholesale price of the gas.[10] However, the *Decision* left the determination of the amount of any such allowance to the discretion of the Commission.[11]

2. *Natural Gas Policy Act.* On November 9, 1978, the Natural Gas Policy Act of 1978 (NGPA), Pub. L. No. 95–621, 92 Stat. 3353 (1978), was signed into law. The NGPA established a specific statutory ceiling price for Prudhoe Bay gas which applies in lieu of the just and reasonable rate which would have been established under the Natural Gas Act.[12] That price is fixed by section 109(a)(4) of the NGPA, which specifically references natural gas produced at the Prudhoe Bay Unit of Alaska for transport through the ANGTS.[13] In addition, section 110(a)(2) of the NGPA permits, to the extent allowed for by rule or order of the Commission, that the section 109 ceiling price shall not be considered to be exceeded to the extent necessary to recover costs of compressing, gathering, processing, treating, liquefying or transporting such natural gas or other similar costs borne by the seller. Thus, determining the maximum lawful price for the Prudhoe Bay gas requires the Commission to determine what, if any, allowances should be permitted under section 110.

It is clear that the Congress, in drafting the NGPA, was aware of the special circumstances surrounding ANGTS. The peculiar and extraordinary problems which attend the production of natural gas at Prudhoe Bay, and its processing and conditioning to the stringent requirements of the ANGTS, were described on the floor of the Congress.[14] The legislative history of the

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[8] *See Decision* at 46.

[9] The Report, following page 84 of the *Decision*, accompanied the *Decision*, and may be regarded as authoritative legislative history. *Midwestern Gas Transmission v. FERC* 589 F. 2d 603, 611 n. 23 (D.C. Cir. 1978).

[10] The actual costs of gathering and conditioning were estimated to be about 30 cents per MMBtu (1975 dollars). The range presented was intended to cover the spectrum of possibilities between a Commission determination that no add-on be provided and a determination that all these costs should be passed on to gas consumers.

[11] *See, e.g., Decision* at 95: "When the costs of service price of the Alcan project is added to a well head price of $1.45 to $1.75 per MMBtu (*depending on the amount the FPC will allow producers for their processing costs*), the wholesale or "city gate" price of the gas should be about $2.50 to $2.80 per MMBtu in constant 1975 dollars." (emphasis added). *See also Natural Gas Pipeline from Alaska: Joint Hearing Before the Subcomm. on Energy and Power, Comm. on Interstate and Foreign Commerce, and the Subcomm. on Indian Affairs and Public Lands of the Comm. on Interior and Insular Affairs,* House of Representatives, 95th Cong., 1st Sess., Ser. No. 95–79, at 219, 224–226, 280–81 (1977) (statements of DOE Secretary Schlesinger in discussing the *Decision* before the House).

[12] Under the NGPA, all "first sales" of natural gas, including those made for shipment through the ANGTS, are controlled by the statutory ceiling prices specified in title I (sections 102 through 110) of the NGPA. Section 2(21) of the NGPA defines a "first sale" as:

> * * * any sale of any volume of natural gas—
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> (i) To any interstate pipeline or intrastate pipeline;
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> (ii) To any local distribution company;
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> (iii) To any person for use by such persons;
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> (iv) Which precedes any sale described in clauses (i), (ii), or (iii); and
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> (v) Which precedes or follows any sale described in clauses (i), (ii), (iii) or (iv) and is defined by the [Federal Energy Regulatory] Commission as a first sale in order to prevent circumvention of any maximum lawful price established under this Act.

[13] In certain circumstances, the Commission may in its discretion set a first sale price under section 109 higher than the dollar amount set by Congress. Section 109(b)(2).

[14] *See, e.g.,* remarks of Senator Stevens, 124 Cong. Rec. S. 16257 (daily ed. Sept. 27, 1978).

NGPA contains frequent references to the special problems of the ANGTS,[15] and special sections of the Act were drafted with specific reference to gas sales made for transport through that system. For example, section 109(a)(4) specifies a particular ceiling price for gas produced from the Prudhoe Bay Unit of Alaska and transported through the ANGTS; section 208 requires that the ceiling price specified in section 109 and costs incurred by any interstate pipeline in transporting the gas should be subject to rolled-in pricing; and section 203(a)(8) provides that other costs (*i.e.*, those allowed under section 110) should be incrementally priced. Yet, despite this obvious attention to the ANGTS, the Congress, in setting a price for the first sale of this gas, made no provision for superseding the policies of either ANGTS or the President's *Decision*. These latter two provisions of law, and the policies they stand for, remain in full force and effect under the NGPA; the NGPA must be implemented in such a manner as to be consistent with them.

3. *Commission action.* As described above, Congress has consistently treated the ANGTS, and the gas produced from Alaska for transport through it, in an exceptional manner. Thus, the ANGTS, as well as the Prudhoe Bay gas to be transported in it, are each *sui generis*. ANGTS construction and initial operation are governed by legislation enacted exclusively for that pipeline system. Moreover, the NGPA recognizes the special nature of the ANGTS, choosing in two instances to apply special rules to Prudhoe Bay production and its pricing; the section 109 price applies irrespective of vintage or other production characteristics as would be applicable to other production and special incremental pricing provisions apply for this gas. The ANGTS is the only pipeline so particularly singled out, by name and producing area, for pricing consideration under the NGPA. The exercise of our section 110 discretion with respect to the gas supply for the ANGTS occurs in that unique context, and is limited to this particular situation.

Because of the special legal status of the ANGTS, the Commission issued a specific proposal to resolve the issues surrounding the conditioning of the gas.[16] That proposal addressed two questions: (1) Who should be responsible for constructing and operating the required conditioning facilities for Prudhoe Bay gas transported through the ANGTS; and (2) what allowances, if any, should be permitted under section 110 of the NGPA for the conditioning of the gas.

The Commission's Notice expressed the view that the public interest would best be served if the producers were responsible for the conditioning facility. Accordingly, the Commission proposed a policy to apply to its consideration of applications for certificates of public convenience and necessity under the Natural Gas Act, which policy would be to approve only those applications which did not require the applicant to bear the conditioning costs, except those costs specifically approved by the Commission. With respect to possible allowances for such costs, the Commission expressed the view that the costs of delivering "pipeline quality gas" to the ANGTS should be covered by the first sale price ceilings provided by the NGPA. The quality standards which determine "pipeline quality gas" were those contained in the March 8, 1977 filing which was approved by the President and the Congress as part of the *Decision*. Thus, the Commission saw no reason to provide any allowances under section 110 of the NGPA over and above the price established by section 109 of the NGPA.

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[15] The discussion of section 208 in the Conference Report accompanying the NGPA provides a particularly good example of Congressional concern for prior legislation surrounding the ANGTS:

> The conferees agreed to provide rolled in pricing for natural gas transported through the Alaskan Natural Gas Transportation System and for the cost of transportation because they believed that private financing of the pipeline would not be available otherwise. Rolled in pricing is the only Federal Subsidy, of any type, direct or indirect, to be provided for the pipeline.

H.R. Rep. No. 95–1752, 95th Cong., 2d Sess. 103 1978). This is in direct reference to the condition in the President's *Decision* requiring that the ANGTS be privately financed. *Decision* at 36.

[16] "Notice of Proposed Rulemaking and Statement of Policy" (Docket No. RM79–19) (issued Feb. 2, 1979), *as corrected*, Errata Notice (Docket No. RM79–19) (issued Feb. 27, 1979).

B. Producer Responsibility for Conditioning

In this proceeding the Commission has considered whether to exercise its section 110 discretion to permit an allowance for production-related costs over and above the maximum lawful price stipulated under section 109 of the NGPA for first sales of natural gas produced at Prudhoe Bay, Alaska for transport through the ANGTS. Stated another way, the Commission must decide which costs of providing pipeline quality gas to the ANGTS should be borne by the seller and which costs should be passed through to the consumer.[17]

The natural gas produced at Prudhoe Bay, Alaska, must be conditioned to supply the gas throughput for a specific pipeline, the ANGTS.[18] This situation is complicated by the fact that the gas is associated with oil and that the gas produced prior to the commencement of gas sales is, or will be, field conditioned and reinjected to enhance the oil recovery. The situation is further complicated by the stringent operating conditions which exist in the producing area and which materially impact the transport of the gas from that area.[19] The Commission has considered each of these factors and has determined that, on balance, the production-related costs for the processing and conditioning should fall upon the producers or other "first sellers" who perform the functions necessary to render the gas transportable through the ANGTS.

The consideration which compels the conclusion that the producers[20] should be responsible for the costs of conditioning gas which will be transported through the ANGTS is the distribution of benefits and burdens which must be associated with the construction and operation of the ANGTS. This includes the benefits and burdens of conditioning the gas and the financial responsibility for the necessary conditioning facilities.

Producers will enjoy significant benefits on the sale of Prudhoe Bay natural gas, and construction of the ANGTS will enable them to market that gas. (*Decision* at 117–118.) The President's *Decision* contemplates that the burdens of undertaking a project to bring needed natural gas from Alaska to markets in the lower-48 states would be borne by the producers, the project sponsors, the private financing community, and the gas-consuming public. (*Decision* at 36–56, 104–127.) We must read the *Decision* as apportioning these burdens to best ensure that the ANGTS will be built and, as built, provide a positive net national economic benefit. Explicit in the *Decision* is the concept that producers should share in the burdens of making the ANGTS a reality. (*See Decision* at 117–118.) For example, while the *Decision* would bar (for antitrust reasons) producer ownership in the ANGTS (*Decision* at 38), it does suggest that the producers should help guarantee the debt necessary to build the ANGTS. (*Decision* at 118.)

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[17] Under sections 203 and 206 of the NGPA, allowances granted first sellers of Prudhoe Bay gas under section 110 will be incrementally priced. Furthermore, under section 601 of the NGPA, allowances permitted under section 110 become part of the maximum lawful price and this price must be considered as "just and reasonable" for purposes of rates charged by jurisdictional pipelines.

[18] In response to the Notice of Proposed Rulemaking, the Exxon Corporation observed that the Commission used the terms "processing" and "conditioning" interchangeably and that these terms have different meanings. The Exxon comments pointed out that gas "processing" is usually done to remove liquefiable hydrocarbons which have a higher value as separate liquids than as a vapor in the gas stream, while "conditioning", on the other hand, involves operations to remove non-hydrocarbon gases or other impurities from the stream. Yet "conditioning" usually precedes "processing." For example, the gas is usually "scrubbed" and dehydrated (i.e., cleaned to remove water droplets, hydrocarbon liquids, and solid impurities) before certain liquefiable hydrocarbons are extracted. This serves a dual function: the gas is prepared for processing and for transportation.

For clarity, the Commission will use the term "conditioning" to apply to all functions necessary for preparing the natural gas to the quality specifications required by the ANGTS. The intent of the Notice was to propose a rule whereby responsibility for all functions performed to prepare the gas for transportation through the ANGTS would be fixed. These functions would include the removal of condensable hydrocarbons to acceptable levels required for efficient gas transportation under the operational and environmental constraints imposed on the ANGTS (*e.g.*, to attain the hydrocarbon dew point quality specification) as well as the removal of non-hydrocarbon gases. The functions would also include chilling, additional water removal, and additional compression, if any, to the pressure necessary for entry into the ANGTS.

[19] *See* pages 4–5 *supra*.

[20] While we speak of "producers" performing conditioning, we should be taken to mean any first seller of this gas.

In addition, there is the burden which attaches to the financing of the conditioning facilities which will be necessary to prepare the gas for pipeline entry. While the *Decision* did not settle the issue as to who should bear this burden, its intent was evident. First, the transportation system described in the President's *Decision* specifically excludes conditioning facilities. Second, the *Decision's* discussion of financing the ANGTS did not consider the impact of the rather sizeable cost (estimated at $2 billion) such facilities would have on the financing of the system. Finally, the *Decision*, in addressing the issue of apportioning conditioning costs, leaves the matter open for decision by this Commission. (*Decision* at 95.) Placing ANGTS sponsors in the position of having to undertake even a part of such a financial burden could adversely affect their ability to finance the ANGTS itself. Likewise, the financing of conditioning facilities by shippers may have detrimental effects on the ANGTS.[21] The Commission believes that any financial resources of the gas transmission industry which are made available to this project should go directly towards support of the ANGTS rather than to conditioning facilities.

Thus, to have producers bear the costs necessary to condition the gas for pipeline entry is to place upon them a burden which we believe is commensurate with the benefits they would receive through the sale of the gas—benefits made possible by the ANGTS and its transport of the gas. Moreover, to have the producers assume responsibility for the capital investment necessary to condition the gas will relieve project sponsors and shippers of an important financial burden.

Producer responsibility for the conditioning facilities provides a useful means whereby producers can aid in the movement of Alaskan gas to lower-48 markets. The *Decision* bars producers from participating in the ANGTS equity ownership. (*Decision* at 38.) Since the processing facilities are not part of the ANGTS,[22] producer responsibility for these facilities provides a way for producers to materially assist in project implementation, and thereby assume a portion of the burden considered by the *Decision* as properly applicable to them.

We conclude that producer responsibility for the costs of conditioning provides benefits to ANGTS implementation and protection for consumers' interests, and comports with the apportionment of burdens manifest in the President's *Decision*. Therefore, the Commission believes that the public interest and the expressions of Presidential and Congressional intent contained in the *Decision* are better served by promoting producer responsibility for conditioning costs, and the Commission intends to exercise its jurisdiction in a manner which would discourage interstate shippers and transporters and, in turn, the natural gas consumers from assuming responsibility for these costs.

C. Exercising Section 110 Discretion For Alaska Production

1. *Section 110 Discretion*. Section 110(a)(2) permits broad discretion as to

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[21] The exception to this generalization is the State of Alaska, in the event it decides to be a shipper of part or all of its royalty gas.

[22] *See* discussion at pages 4–5 *supra*.

the method ("by rule or order") which the Commission is to employ in allowing increases to ceiling prices for production-related costs. Moreover, the words of that section ("any costs * * * borne by the seller and allowed for * * * by the Commission") do not contain limiting language such as that found elsewhere in the NGPA when the Congress intended to circumscribe the Commission's authority.[23] On its face,[24] section 110(a)(2) indicates a Congressional concern for flexibility to weigh necessary factors and determine appropriate allowances. The Commission interprets its authority under section 110 as permitting it discretion to allow all, some, or no production-related costs. This discretion, of course, must be exercised in a reasonable manner.

The legislative history of section 110(a)(2) highlights its discretionary nature. The Conference Report which accompanied the NGPA provides that the Commission "may" allow such costs,[25] and the statement made by the House floor manager of the Conference Report describes the section as being discretionary.[26] In addition, the floor debates which attended the adoption of the NGPA clearly show that section 110(a)(2) was viewed as being discretionary. For example, in response to the questions of Senator Stevens as to the application of section 110(a)(2) to the particular circumstances of Alaska-produced natural gas, Senator Jackson, Senate floor manager of the Act, stated:

> Section 110 of the Act gives FERC authority to increase the maximum lawful price of any natural gas including Alaskan gas, to compensate the seller for costs that they [sic] may incur in the gathering and processing of natural gas. The special circumstances described by my colleague [the difficulties attending Prudhoe Bay production] would be presented to the Commission. The Commission may allow for an adjustment in the maximum lawful price if it determines it is appropriate to do so.

124 Cong. Rec. S16257 (daily ed. Sept. 27, 1978).[27]

While the Conference Report which accompanied the NGPA cites past Commission practices allowing for production-related costs in the setting of just and reasonable rates under the Natural Gas Act, this is its only explicit reference to the Natural Gas Act in the implementation of section 110(a)(2).[28] The Commission does not interpret this reference as constricting or defining the commission's section 110 discretion in terms of the Commission's past practices under the Natural Gas Act.[29] Instead, the Commission interprets it as a reference to the setting of maximum lawful prices by reference to just and reasonable rates in existence at the time the NGPA was passed (e.g., section 104 prices). By this paragraph, the Conferees recognized the fact that just and reasonable rates were set inclusive of some production-related costs and that the Commission, in considering ceiling prices referenced by such just and reasonable rates need not, because of section 110, attempt the administratively burdensome task of stripping the old allowances from established rates merely to consider them again under section 110.

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[23] For example, section 110(a)(1), which provides for state severance taxes borne by sellers, is clearly non-discretionary.

[24] Section 110(a) states, with reservations not relevant here, that:

* * * a price for the first sale of natural gas shall not be considered to exceed the maximum lawful price applicable to the first sale of such natural gas * * * if such first sale price exceeds the maximum lawful price to the extent necessary to recover * * * any costs of compressing, gathering, processing, treating, liquefying, or transporting such natural gas, or other similar costs, borne by the seller and allowed for, by rule or order, by the Commission.

[25] "All ceiling prices under this Act are exclusive of state severance taxes borne by the seller and *any adjustment which may be allowed* by the Commission for specified production-related costs." H.R. Rep. No. 95-1752, 95th Cong., 2d Sess. 90 (1978) (emphasis added).

[26] "With respect to section 110, it has been correctly observed that the authority to permit adjustments is discretionary. However, by authorizing discretionary adjustments the Conferees did not intend to authorize a refusal to grant appropriate allowances where such refusal would be an abuse of discretion." 124 Cong. Rec. H13116 (daily ed. Oct. 11, 1978) (remarks of the Hon. John Dingell).

[27] *See also* the colloquy between Senators Gravel and Jackson wherein Senator Gravel speaks of the "permissive nature of the Commission's power to provide, by rule or order, an allowance in excess of the maximum lawful price * * *." 124 Cong. Rec. S16257 (daily ed. Sept. 27, 1978).

[28] "The conferees recognize that, in certain cases, the just and reasonable rates under the Natural Gas Act include an allowance for production related costs. The conference agreement [respecting section 110(a)(2)] is not intended to alter or change that practice." *Conference Report* at 91.

The clearest expression of limits to section 110 discretion is found in the statement of Congressman Dingell (on presenting the NGPA to the House):

> With respect to section 110, it has been correctly observed that the authority to permit adjustments is discretionary. However, by authorizing discretionary adjustments the conferees did not intend to authorize a refusal to grant appropriate allowance where such refusal would be an abuse of discretion. Thus, if the function performed is not usually performed by the producer without provision being made for compensation over and above the amounts paid for the gas, prevailing industry practice may guide FERC to approve ceiling price adjustments which the Commission determines appropriate and consistent with the purposes of the legislation. For example, if the producer undertakes to compress the gas to pipeline pressure, and if an allowance is customarily made by the pipeline for such compression, the conferees anticipated that FERC would consider approval of an appropriate allowance under section 110. However administrative flexibility was deemed important. Therefore, it was also intended that FERC could selectively focus on the areas which appear appropriate for approval of adjustments under section 110 in such a manner that the implementation of the section would not become administratively burdensome.

124 Cong. Rec. H13118 (daily ed. Oct. 11, 1978).

Congressman Dingell's example of a pipeline customarily making payment to a producer for a particular production-related service merely anticipates that the Commission may consider such an allowance. While "prevailing industry practice" and contracting custom are to be carefully considered by the Commission, neither are viewed as requiring an allowance. For reasons of administrative flexibility, the Commission has discretion broad enough to "selectively focus on the areas which appear appropriate for approval of adjustments under section 110."[30]

We believe that the flexibility to administer section 110 includes the ability to consider exceptional circumstances such as the Prudhoe Bay Unit. That section 110, on its face, makes no distinction for particular categories of natural gas sales or producing areas does not mean that the Commission cannot and should not treat individual producing areas differently. When good reason exists to provide for the treatment of production-related costs for particular producing areas, the Commission should exercise its discretion in a manner consistent with that reason. The exceptional nature of the Prudhoe Bay producing area provides such a reason.

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[29] In its initial comments to this rulemaking, Exxon argued that the Congressional intent of section 110 was to "permit the Commission to do that which it had the authority to do under the Natural Gas Act, i.e., to permit producers to recover such costs as they might incur beyond the wellhead for transportation functions." Exxon goes on to argue that (1) the services enumerated under section 110 are transportation-related and have been considered as such by the Commission under national rate orders; (2) that the practices of these orders (to leave the apportioning of such costs to contracting parties) was considered by Congress; and (3) therefore, Congress must have meant that our discretion under section 110 was limited to our prior considerations under the Natural Gas Act. Comments of Exxon Corporation at 9–12 (Docket No. RM79–19) (filed March 19, 1979). Reply comments of the Commission Staff addressed the weakness of Exxon's premise that action under such opinions as Opinion No. 749 or 770–A did not consider processing and conditioning costs. The response showed the history that the opinions did consider such costs. Reply comments of the Federal Energy Regulatory Commission Staff at 2–3 (Docket No. RM79–19) (filed April 19, 1979). More importantly, however, there are the clear words of the statute; the various functions listed under section 110 are listed as "production-related" and they are set in the context of costs borne by first sellers.

[30] 124 Cong. Rec. H 13118 (daily ed. Oct. 11, 1978) (statement of Congressman Dingell).

2. *Exercising discretion for Alaska production.* Subpart K, Part 271 of the Commission's Interim Regulations under the NGPA implementation section 110. Those regulations prescribe rules by which a first seller of natural gas may collect more than the applicable maximum lawful price to recover State severance taxes and certain production-related costs borne by the seller. Section 271.1100(b) of that subpart provides that regulations permitting the recovery of any allowances, other than State severance taxes, will not apply to first sales of natural gas produced from the Prudhoe Bay Unit of Alaska and transported through the ANGTS. This exclusion rested upon the Commission's belief that, because of the special circumstances surrounding the production of this gas, it was necessary to promulgate a separate rule to take into consideration the provisions of the ANGTA and the President's *Decision* as well as the NGPA.

In February of this year, the Commission issued a notice proposing a rule barring any section 110 allowances for this gas production.[31] That proposal rested upon the Commission's view of section 110 discretion, and the concern that it be properly exercised in light of the constraints imposed by the President's *Decision.* As noticed, the Commission proposed: (1) That producers be responsible for conditioning the gas transported through the ANGTS; (2) that they receive no allowance under section 110 for the costs to condition the gas; and (3) to ensure that these costs would not be shifted to consumers, a policy statement under the Natural Gas Act which would bar transporters or shippers from passing through costs the Commission viewed as properly resting upon producers. The rationale for the notice rested in part upon the presumed consequences of having consumers bear production-related costs and the resulting impact this would have on marketing the gas and financing the pipeline. It also rested, in part, upon what we perceived as the rationale of the *Decision,* that producers bear the responsibility for financing the conditioning facilities necessary to make the gas transportable.

Several comments argued that the proposed rule would be inconsistent with both the letter and the intent of the NGPA.[32] These comments can be summarized as follows: first, that section 110 provides a right of compensation for production-related costs for any of that section's enumerated functions performed by a first seller; and second, that to the extent the Commission failed to provide an allowance above the section 109 price for a seller who undertook the production-related functions, the failure worked an unlawful reduction in the section 109 price.

Legislative history was cited for the proposition that the section 109 price must apply to a wellhead sale and that producers must therefore be left free to negotiate the apportionment of production-related costs. That citation was to a colloquy between Senators Gravel and Jackson:

> *Senator Gravel:* Senator, I infer that the permissive nature of the Commission's power [under section 110] to provide, by rule or order, an allowance in excess of the maximum lawful price for any costs of gas borne by the seller does not preclude a purchaser from acquiring natural gas at the wellhead, paying the maximum lawful price at that point.
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> *Senator Jackson:* The Senator is correct.[33]

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[31] "Treatment of Certain Production-Related Costs for Natural Gas to be Sold and Transported through the Alaskan Natural Gas Transportation System", Notice of Proposed Rulemaking and Statement of Policy (Docket No. RM79-19) (issued Feb. 2, 1979), *as corrected,* Errata Notice (Docket No. RM79-19) (issued Feb. 27, 1979).

[32] These included the comments filed by Panhandle Eastern, Exxon, Mobil, Atlantic Richfield, Sohio, and the State of Alaska.

[33] 124 Cong. Rec. S16257 (daily ed. Sept. 27, 1978).

This colloquy should be read in its proper context. Clearly, Commission discretion does not, under NGPA, reach to barring a wellhead first sale at the maximum lawful price. The comments of Senator Gravel only go to underscore what is evident on the face of section 110—the discretion of that section cannot be exercised to reduce a ceiling price; it can only be used to increase that price. Second, the colloquy should be read as saying *if* raw, unconditioned gas was sold then it *may* be sold at the section 109 price. It should not be read as mandating a greater price to compensate for any conditioning which must attend such a sale;[34] such a reading would be in clear derogation of the discretion specifically given the Commission under section 110. Finally, Senator Gravel does not address the issue of what other power the Commission may have, separate from that of the NGPA, which it may use to apportion production-related costs; he speaks only with reference to section 110.

Arguments that the section 109 price contains no provision for production-related costs are in error for they are premised upon the mistaken notion that the section 109 ceiling price applies only to first sales of raw, unconditioned gas made at the "wellhead". That this is not true can be seen by examining section 2(21) of the NGPA. That section defines a "first sale" in terms of *to whom* the sale is made, and not in terms of *where* in the production and transportation flow the sale occurs. Moreover, such reading of the NGPA would be inconsistent with our discretion under section 110 of that Act.

Comments also raised the point that to bar first sellers of Prudhoe Bay gas from the allowance provisions of section 110 of the NGPA worked an unlawful discrimination against such sellers. This argument is premised on the erroneous view that section 110 requires both a uniform treatment of all domestic gas and a uniform result. We are of the opinion that the Commission's authority under section 110 is, of necessity, broad enough to consider special provisions for particular regions if a good reason to do so exists. The practice of recognizing special conditions for the quality of gas produced in different areas (well established under the area-rate proceedings) is necessary for the proper exercise of the discretion of section 110. The recognition of area differences means that uniform results are not required.

Comments argued that the Commission does not have an adequate factual record to support a special rule for section 110 allowances for Alaska. It was argued that any action taken to reject, in advance, an application under section 110 is an action taken without the circumstances of Prudhoe Bay gas production being fairly presented to the Commission, and therefore, no basis exists for a prior rejection of section 110 applications. These comments maintained that any determination for allowances should be made only after the Commission receives gas purchase contracts and considers the factual circumstances relating to the conditioning of the gas for the ANGTS.

The charge that the Commission lacked a record in support of its proposal went principally to the

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[34] That Senator Gravel did not consider such an outcome may be seen in the colloquy placed immediately after the one just cited. Again engaged in questioning Senator Jackson (this time on the interplay of sections 203 and 208 of the NGPA respecting the incremental pricing of Alaskan gas), Senator Gravel queries:

Does the distinguished Senator from Washington agree that the combined effect of section 208 and section 203 of the conference report mandate rolled-in pricing for all acquisition costs of gas produced from the Prudhoe Bay unit and transported through the Alaska Natural Gas Transportation System? Rolled-in pricing would include the wellhead price and processing, gathering, conditioning, and compression costs borne by the producers of such gas, which, in the aggregate, are less than $1.45 per MMBtu's [the section 109 price], as adjusted for inflation, plus all costs associated with the transportation of such gas to markets in the lower 48 States.

124 Cong. Rec. S16257 (daily ed. Sept. 27, 1978). Clearly, the section 109 price was viewed as including at least some production-related costs.

Commission's presumption that granting allowances under section 110 would have a detrimental impact in the marketability of the gas transported through the ANGTS. In refutation of this presumption, Exxon presented a study as to the marketability of the gas presuming costs of conditioning of up to 60 cents per thousand cubic feet of gas.

In addition, comments cited to earlier studies to the same effect. In light of the comments, we agree that the presumption, and its attendant rationale of granting (or not granting) section 110 allowances, lacks a sufficient record to form the basis for exercising Commission discretion under section 110. It is still too early to determine either the precise costs of preparing the gas for transport or the impact such costs would have on the city-gate price and, consequently, the marketability of the gas. In addition, based on the data now available to the Commission in this rulemaking, marketability of the gas should not be a serious concern. This Order is not premised on marketability.

The charge that the Commission lacked a factual record sufficient to take the type of actions noticed for this rulemaking also went to the circumstances surrounding the production and conditioning of the gas for pipeline entry. Apart from the factors presented to us by comments to this rulemaking, the information available to the Commission on Prudhoe Bay production includes the record before the Federal Power Commission in the *El Paso Alaska Company* (Docket No. CP75-96 *et al.*) and the Congressional consideration of the President's *Decision* and the NGPA. We believe, therefore, that we possess an adequate knowledge of the factors necessary to consider the issue of exercising section 110 discretion for sales of this gas. These factors include the fact that the gas was specially considered under the NGPA, that the gas must be conditioned to permit its transport from the producing area, and the operative policies of the President's *Decision* from which we can determine who should bear the cost of that conditioning.

3. *Considerations in exercising discretion.* Alaskan gas is useful to a purchaser only if transported to the marketplace of the lower-48 States—i.e. only if it is conditioned to render it transportable by the pipeline. Any further conditioning would increase the efficiency of the transportation; the costs which attend these functions should be allowed under section 110. In our opinion, however, no allowance should be made for the costs of conditioning the gas to render it transportable.[35]

In determining the application of section 110 for the lower-48 States we started with the presumption that industry practice determines what functions are normally performed by producers. We were persuaded that the common quality standards reflected in interstate producer sales contracts on file with the Commission served as a useful indication of the prevailing practice as to which functions were assumed by producers and to what standards.[36] However, to use Prudhoe Bay producer contracts to establish which costs are "normally" borne by Alaskan producers to tender transportable gas is inappropriate to Alaskan first sales.

The contracts which yielded the prevailing practices of the lower-48 were contracts established over time and prior to the NGPA. The contracts which have been (or will be) negotiated for the sale of Prudhoe Bay gas do not (and will not) share these characteristics.[37] To use

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[35] *See* Section B, *Supra.*

[36] *See Preamble* to the Commission's Interim Regulations under the Natural Gas Policy Act of 1978 at 79 (Docket No. RM 79-3) (issued Dec. 1, 1978), 43 *Fed. Reg.* 56490 (Dec. 1, 1978).

[37] The Commission is aware of but two contracts for this gas: the first between Exxon Corporation and Northern Natural Gas Company, dated April 30, 1979 (May 25, 1979, letter of Mr. David B. Ward to Mr. Kenneth F. Plumb, Secretary to the Commission); the second between Exxon Corporation and Pacific Gas and Electric Company, dated March 27, 1979 (May 24, 1979, letter of Mr. Gilbert L. Harrick to Mr. Kenneth F. Plumb). In addition, the contracts for the sale of this Alaskan gas are made contingent upon the outcome of this rulemaking.

Alaskan contracts as an indicator of prevailing industry practice for Alaska would permit the first contracting parties to establish a "practice", which in turn would dictate the scope of Commission discretion under section 110. To permit this circularity would be an abrogation of the Commission's lawful responsibility.[38]

The ANGTS is a pipeline requiring special standards to make the gas transportable; therefore, the average standards of the lower-48 as reflected in § 271.1105 of the Commission's Regulations are inapplicable. Gas produced at Prudhoe Bay for transport through the ANGTS must meet particular pipeline quality standards to be transported at all.[39] These standards indicate the functions which must be performed to condition the gas for producer processing and pipeline entry. Thus, the gas must be chilled; it must be free of excessive water, liquid hydrocarbons, sulfur and hydrogen sulfide, carbon dioxide, oxygen and impurities; and it must be compressed. Those are all functions which, on the basis of applicable benefits and burdens, we believe should be borne by the producers.

Comments in this proceeding stressed that a proper application of the Commission's discretion under section 110 requires that allowances be made for those processing and conditioning functions which are solely tied to transporting the gas, and that, at the very least, allowances should be made for certain production-related costs not ordinarily borne by producers. We reject this approach because almost all of the functions traditionally performed by producers are, to some extent, transportation-related—their performance enables the gas to enter the transporting pipeline. However, one function impresses the Commission as requiring special consideration—the removal of carbon dioxide below the point required for reliable pipeline operation. In our opinion, that entails exceptional costs that go beyond making the gas transportable. An allowance for this particular cost should therefore be made.

The pipeline quality requirements proposed for the ANGTS include carbon dioxide content of not more than one percent by volume.[40] The rationale for this low carbon dioxide content rests upon two factors: (1) Some carbon dioxide removal is required to prevent corrosive chemical reactions in the pipeline which would jeopardize operating reliability of the system, and (2) a low carbon dioxide content, by permitting the transportation of a greater volume of gas, would enhance the transportation efficiency of the system.

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[38] The use of producer sales contracts for Alaska is particularly difficult given that these contracts will not be subject to the same regulatory review as was permitted prior to the NGPA. With respect to the "letters of intent" entered into for the sale of Prudhoe Bay gas, the same objections hold against their use as an indicator of prevailing practice.

[39] That the *Decision* considers the standards of the initial sponsor, ALCAN, see notes 4 to 6 *supra* and accompanying text. *Pro forma* tariffs submitted under Docket No. RM78-12 reflect similar standards. *See* Alaskan Northwest Natural Gas Transportation Company, FERC Gas Tariff, Original Volume No. 1, Original Sheet Nos. 216–217 (filed March 12, 1979); Northern Border Pipeline Company, Pro Forma FERC Gas Tariff, Original Volume No. 1, Original Sheet Nos. 215–216 (filed March 12, 1979). Under Docket No. RM78-12 the Commission accepted all of the standards submitted on the *pro forma* tariffs except those dealing with carbon dioxide. Order No. 31 at 213–215 (Docket No. RM78-12) (issued June 8, 1979). In comments filed on May 4, 1979, in Docket No. RM78-12, Sohio contended that the quality standards for water content and sulfur (hydrogen sulfide, mercaptan sulfur and total sulfur) are too stringent, and are not justified by considerations of avoiding jeopardy to the pipeline. Order No. 31 noted that "[t]he exact quality standards required for gas to be transported through ANGTS will, of course, depend upon the final design of the system," and that "the water and sulfur standards proposed by the transporters will be permitted to be included in the tariffs subject to any revisions that may be required to comport with the final pipeline system design." (Order No. 31, pp. 214–215.) The final pipeline system design will be determined in hearings in Docket No. CP78-123 *et al.* Sohio, and any other interested party, can and should raise in those hearings any questions they may have as to excessive stringency of the water and sulfur standards in the tariffs in light of the final pipeline system design, and all parties should have an opportunity in those hearings to present factual evidence pertinent to those standards. It is our intention that the water and sulfur standards ultimately confirmed in the tariffs should be sufficiently stringent to protect the pipeline, but that the producers (or other first sellers) should not have to bear the cost of removing water or sulfur beyond the level necessary to ensure safe operation of the pipeline.

[40] The 1 percent carbon dioxide figure was first proposed in the initial Alcan filing. Most recently it was proposed in *pro forma* tariffs submitted to this Commission in proceedings under Docket No. RM78-12.

A three percent by volume carbon dioxide content is a common standard in industry practice. Thus, although the Commission may find that the public convenience and necessity requires that natural gas delivered for transportation through the ANGTS should be conditioned to a standard more stringent than three percent,[41] gas conditioned to that more stringent standard is not required for the entry of the gas stream into the pipeline. On the other hand, it seems clear that the gas must be conditioned to at least the three percent standard to avoid the risk of corrosion of the pipeline.[42] The Commission believes that the cost of removing carbon dioxide to the three percent standard is a function commonly undertaken by producers in order to make the gas transportable to the marketplace, and therefore does not warrant an allowance under section 110. The cost of additional carbon dioxide removal (which the Commission might require) however, is not necessary for providing a commodity capable of pipeline entry; additional removal would be based on considerations of economic efficiency. Therefore, such cost, if incurred, should be considered for an allowance under section 110.

The Commission by this rule does not decide what allowances should be granted or what costs are involved. Such decisions must rest upon the facts of particular cases presented pursuant to the application procedures set forth in § 271.1105.[43] The Commission only decides herein that allowances should be made for the carbon dioxide removal function defined above.

4. *Result.* By amending the interim regulations, the Commission has established a rule which permits producers or other first sellers of Prudhoe Bay gas an application process under section 110 to recover only those production-related costs incurred for the removal of carbon dioxide to levels below three percent by volume. To this end, the Commission has deleted the exception provisions of § 271.1100(b) of its interim regulations, and has added a new clause to § 271.1105.

In addition, the Commission, by deleting the exception of § 271.1100(b), intends to permit producers or other first sellers of Prudhoe Bay gas to avail themselves of the procedures of § 271.1106 of the interim regulations to

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[41] The precise carbon dioxide standard for the ANGTS was one of the issues left unresolved by the Commission in Order 31. That issue will not be resolved herein, but will be the subject of a Commission order in Docket No. RM78-12. *See* Section E 1 *supra.*

[42] Of the four alternative proposals for an ANGTS considered by the FPC (two of those proposals were from the current project sponsor's predecessor), the most lenient carbon dioxide content standard was 3% by volume, in the Arctic Gas proposal. Thus, the Commission concludes that adequate system reliability for the design conditions expected for ANGTS operations would likely require carbon dioxide removal to a maximum of 3%.

Under the provisions of Section 9 of the Agreement on principles between the U.S. and Canada (pages 47–63 of the *Decision*), this matter has been discussed with representatives of Canada's National Energy Board.

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[43] For example, an important factor in determining whether an allowance should be granted for costs incurred in lowering a carbon dioxide content from 3% to 2%, and the amount of such an allowance, should be who would receive the benefits associated with the more extensive removal of natural gas liquids that such reduction would bring about.

petition for relief under section 502(c) of the NGPA. The grounds for such relief would be those stipulated by section 502(c).

Thus, a first seller who performs production-related functions may apply under section 502(c) for relief or waiver of the Commission's regulations.

D. Policy Under the Natural Gas Act

The regulations just discussed do not address the situation of a purchase of Alaskan gas, at a maximum lawful price, when the gas has not been conditioned to permit its transportation. The Commission has a responsibility under the Natural Gas Act to consider the impact on the ultimate consumer of a sale in which the buyer purchases unconditioned gas when the buyer is purchasing the gas for a sale for resale in interstate commerce.[44] The Commission has the authority under the Natural Gas Act to approve or disapprove the rates charged by pipelines engaged in interstate commerce that might assume the costs of conditioning the gas in addition to the costs of purchasing and transporting the gas. This authority is exercised when pipeline companies file tariffs with the Commission. If the Commission were to approve tariff provisions that included conditioning costs, then interstate pipelines could agree to purchase gas which had not been conditioned, condition it themselves (or pay a third party to do it) and then recover the costs of conditioning the gas (in addition to the cost of purchasing the gas) in the price they charge on resale. In this manner the very considerations upon which it was determined that producers should bear the burdens of conditioning gas for ANGTS transport, and upon which allowances were denied under section 110, would be jeopardized.

For the reasons set forth at length in the preceding sections of this Order, the Commission has determined that its discretion under section 110 of the NGPA ought not to be exercised in such a manner as to grant allowances for conditioning costs (except for carbon dioxide removal below 3 percent). That determination was based on our analysis of the comparative benefits and burdens borne by producers, transporters, shippers, and consumers of the Prudhoe Bay gas. As discussed above, in light of the benefits received by the producers through the availability of the ANGTS, enabling the producers to market the gas, as well as the sizeable burdens already imposed on transporters and consumers as a consequence of the enormous cost of the ANGTS, we have determined that neither the transporters nor the consumers should have to bear the additional burden of paying for the conditioning costs. By this Order, the transporters and shippers have now been put on notice of those Commission determinations. Accordingly, those determinations give rise to a rebuttable presumption that it would be imprudent for any transporter or shipper to incur such conditioning costs. Transporters and shippers are now on notice that the Commission's policy is to exercise its responsibilities under the Natural Gas Act in such a manner as to prevent the pass through to consumers of such presumptively imprudent costs.[45]

Therefore, in any action involving the acceptance and approval of tariffs filed with the Commission, or consideration of applications to construct or acquire facilities (whether they are submitted in conjunction with applications for certificates of public convenience and necessity for the construction and operation of the ANGTS, or whether they are for the sale or transport of gas through that system), it will be the policy of the Commission, to presume that costs incurred by transporters or shippers to condition natural gas for transportation through the ANGTS are costs not prudently incurred. Absent rebuttal of that presumption, the Commission would not accept or approve tariff filings which permit the transporter or the shipper-purchaser to include the costs of conditioning gas in the rates or charges as an addition to the cost of purchasing the gas at the maximum lawful price. Additionally, absent rebuttal of the presumption, the Commission will deny any applications by any jurisdictional companies for authority to construct, acquire or operate facilities to perform such conditioning unless such facilities are financed by the producers, or by someone other than transporters or shippers of the gas.

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[44] 15 U.S.C. 717(b). The Commission would not be concerned if a purchaser who bought the gas for its own use rather than for a sale for resale agreed to bear the costs of conditioning the gas. Nor would the Commission be concerned if the State of Alaska sold its royalty share of the gas to consumers within Alaska and paid for the costs of conditioning the gas. Neither situation involves the Commission's jurisdiction under the Natural Gas Act over sales of gas for resale in interstate commerce.

[45] This conclusion is based on the premise that the producers will contract with purchasers for the sale of Prudhoe Bay gas at no less than the maximum lawful price set by section 109 of the NGPA. If the parties agreed to a sales price lower than the section 109 (NGPA) ceiling with the pipeline paying for some conditioning costs, the Commission would not necessarily oppose such an outcome provided the total price paid for pipeline quality gas did not exceed the applicable section 109 (NGPA) price.

The policy does not apply to such costs as are allowed pursuant to Commission action taken under Part 271, Subpart K of its regulations.[46] Also, the policy would not apply to costs incurred in reducing the carbon dioxide content of the gas from 3 percent of its volume to below 3 percent of its volume, should the transporter or shipper purchase gas whose carbon dioxide content has not been reduced from 3 percent to below 3 percent.

When such tariffs are filed, the Commission will consider whether the provisions thereof are consistent with this policy statement. It will also be the practice of the Commission to consider whether any proposed revisions in tariffs involving the transportation of gas through the ANGTS, filed under section 4 of the Natural Gas Act, contain provisions which are not consistent with the policy set forth herein.

The Commission received a number of comments on the policy statement proposed in its initial notice of this rulemaking. As proposed, the policy was directed toward granting certificates of public convenience and necessity. After considering the comments, the Commission has revised the proposed policy so that it applies to the approval of tariffs filed with the Commission as well as to applications for certification.

Several of the comments to this rulemaking contended that the policy statement, as proposed, is a contravention of the NGPA, a violation of clear Congressional intent respecting the NGPA, and a violation of the Natural Gas Act. Both Sohio and ARCO argued that the proposed policy would unlawfully reduce the statutory ceiling price established under the NGPA for a sale of Prudhoe Bay Gas by forcing the producers to bear all of the gathering and conditioning costs.[47] They contended that the NGPA allows producers the right to sell their gas at the wellhead for the maximum lawful price and leaves them free to negotiate the allocation of conditioning costs between the seller and the purchaser. In support of this argument they cited statements taken from the floor debate on the NGPA between Senators Gravel and Jackson wherein Senator Gravel stated:

> * * * that the permissive nature of the Commission's power to provide, by rule or order, an allowance in excess of the maximum lawful price for any costs of gas conditioning borne by the seller does not preclude a purchaser from acquiring natural

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[46] A pipeline may include the costs of conditioning gas in its rates under Part 271 of the regulations in the following circumstances. Where the Commission approves an application made by the seller under § 271.1105 of the regulations, the pipeline may pass through the costs to the extent they are allowed to the seller by the Commission. Second, where the Commission denies an application for an allowance filed pursuant to § 271.1105, and where the Commission grants an application filed by the seller under § 271.1106, then the costs borne by the pipeline may be passed through.

[47] ARCO Comments at 3; Sohio Comments at 12.

gas at the wellhead, paying the maximum lawful price at that point.[48]

The Commission's policy does not unlawfully reduce the maximum lawful price or prevent the apportioning of conditioning costs by producers and purchasers through contract negotiation. The policy does not preclude a purchaser from acquiring natural gas at the wellhead at any lawful price, including the maximum lawful price. What the policy proscribes is the pass-through of costs imprudently borne by the purchaser which attends the purchase of raw, untreated gas.

In its comments, Exxon claims that adopting the policy violates section 601(c) of the NGPA.[49] Exxon argues that producers are authorized to sell gas at the maximum lawful price under section 109 of the NGPA and that, accordingly, the purchasers are entitled to flow through the ceiling price under Section 601(c)(2). The Commission's policy does not violate section 601 of the NGPA. Section 601 applies only to first sales prices. Amounts not paid in a first sale are not covered under Section 601. The maximum lawful price for sales of gas produced in the Prudhoe Bay Unit, Alaska for transportation through the ANGTS is established by section 109 of the NGPA. Unless and until the Commission permits an addition to this price under section 110 of the NGPA, the ceiling price of section 109 is the maximum lawful price. The Commission's policy prevents only the flow-through of costs which are 110-type but not approved under section 110, and does not prevent the flowthrough of the price established by section 109. Thus, the Commission's policy conforms with section 601.

Panhandle Eastern Pipeline Company contended in its comments that the policy statement summarily forecloses the opportunity to present, under the Natural Gas Act, and to be heard thereon, any proposal at variance with the policy.[50] This misconceives the effect of a statement of policy. In *Pacific Gas and Electric Company* v. *Federal Power Commission*, 506 F.2d 33 (D. C. Cir. 1974), the Court of Appeals described the effect of a general statement of policy:

> A general statement of policy is not finally determinative of the issues or rights to which it is addressed. The agency cannot apply or rely upon a general statement of policy as law because a general statement of policy only announces what the agency seeks to establish as policy. A policy statement announces the agency's tentative intentions for the future. When the agency applies the policy in a particular situation it must be prepared to support the policy just as if the policy statement had never been issued. (506 F.2d at 38.)

The Commission's policy statement does not complete the regulatory process with regard to the proper assignment of production-related costs. When gas purchase contracts are executed, and tariffs and applications for certificates are filed with the Commission, such tariffs and applications will be subject to the review and approval requirements of the Natural Gas Act.

E. Other Issues

The comments have raised several other important issues. These include the relationship of this proceeding to ANGTA, arguments raised by the Department of Justice that producer ownership of the processing or conditioning facilities involves antitrust problems, consideration of the appropriate carbon dioxide standard for the ANGTS, and arguments raised against the procedures used in this rulemaking.

1. *Commission action under ANGTA.* Section 9 of the ANGTA directs federal

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[48] 124 Cong. Rec. S16257 (Sept. 27, 1978).

[49] Comments of Exxon Corp., at 33 (filed March 19, 1979). Section 601(c) prohibits the Commission from denying or conditioning the grant of a certificate based upon the amount paid for the gas, if such amount is deemed just and reasonable under section 601(b) of the NGPA. Section 601(b)(1)(A)(i) of the NGPA provides that any amount paid in any first sale of the natural gas shall be deemed to be just and reasonable for purposes of sections 4 and 5 of the Natural Gas Act if such amount does not exceed the applicable maximum lawful price under title I of the NGPA.

[50] Comments of Panhandle Eastern Pipe Line Company at 7 (filed March 17, 1979).

agencies responsible for the grant of any authorization "necessary or related to the construction and initial operation" of the ANGTS to issue such authorizations "at the earliest practicable date." 15 U.S.C. 719g. The regulations and the policy statement issued under this Order are necessary and related to the construction and initial operation of the ANGTS. These actions are required to establish the regulatory framework in which the gas sales contracting process can proceed. Also, investors will not agree to finance the ANGTS until cost allocations are established. This contracting process is an essential predicate for virtually all future government and private actions to build the ANGTS.

The policy statement adopted by this Order is intended to foster the objectives of the regulations, and is thus related to the construction and initial operation of the ANGTS. Because the phrase "necessary *or* related" in section 9 of the ANGTA is a disjunctive phrase, the "related" nature of these actions would in itself bring them within the ambit of ANGTA jurisdiction. These actions are also, in our view, necessary to the implementation of the project.

In its reply comments, Exxon contended that the Commission's actions in this rulemaking are based upon the NGPA and not the ANGTA, and that the ANGTA, being addressed only to matters involving the selection of a pipeline for transportation of gas from Alaska, contains no provisions relating to the pricing of Alaska gas.[51] The Commission disagrees. Section 9 of ANGTA, 15 U.S.C. 719g, implements the legislative purpose of the Act, "to expedite * * * construction and * * * operation" of the system approved under the Act. The substantive authority exercised by the Commission under the NGPA and the Natural Gas Act, to the extent applicable to actions "necessary or related" to the construction and initial operation of the ANGTS, must then be exercised in accordance with the requirements of section 9 of the ANGTA.

Some comments suggested that section 9 of the ANGTA only applies when an application is made for one of the authorizations specified in section 9(a) of the ANGTA, and that the Commission is not deciding the merits of any such application in this proceeding.[52] We find this argument unpersuasive. A policy regarding the approval of tariffs related to the construction and operation of the ANGTS should receive the same expedited consideration as a certificate to construct. This is consistent with the purpose of the ANGTA. Second, with regard to the amendments to the interim regulations under the NGPA, section 9(a) of the ANGTA applies to "a certificate, right-of-way * * * or other authorizations to be issued or granted by the federal officer or agency * * *." The term *"authorization"* is, in our view, broad enough to include the decision whether to permit sellers of gas produced in the Prudhoe Bay Unit, Alaska an adjustment to the maximum lawful price established by the NGPA.[53]

2. *Antitrust issues.* The Department of Justice in its comments expressed concern with the anticompetitive impact that might result from producer ownership of the gas conditioning plant. That concern was based in large part upon the premise that all gas developed

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[51] Reply comments of Exxon Corporation at 16.

[52] *See*, Reply comments of Exxon, at 19; Reply comments of Atlantic Richfield Company, at 4–6. Section 9(a) reads, in pertinent part, as follows:

(a) To the extent that the taking of any action which is necessary or related to the construction and initial operation of the approved transportation system requires a certificate, right-of-way, permit, lease, or other authorization to be issued or granted by a Federal officer or agency, such Federal officer or agency shall—(1) to the fullest extent permitted by the provisions of law administered by such officer or agency, but (2) without regard to any provision of law which is waived pursuant to section 719f(g) of this title issue or grant such certificates, permits, rights-of-way, leases, and other authorizations at the earliest practicable date.

[53] Exxon and Sohio make several arguments in their comments relating to the applicability of the

on the North Slope would be handled by the gas conditioning plant at the Prudhoe Bay field; the assumption that this plant would be characterized by economies of scale so great that it would constitute a competitive "bottleneck," and thereby restrain or entirely eliminate the opportunity for future competition in the relevant market from other facilities; and that the tariffs of the gas conditioning plant will not be regulated by the Commission. To eliminate any monopoly potential, the Department of Justice proposed that the Commission promulgate special rules for the gas conditioning plant.[54]

The Commission shares the Justice Department's concern about creating a situation that could lead to the development of unchecked monopoly power. However the Commission believes that the issues raised by the Justice Department do not need to be resolved in this Order, and should be deferred for resolution in a later proceeding, if then necessary and appropriate.

The Commission's February 2, 1979 Notice contemplated the adoption of a policy requiring, *inter alia*, that the conditioning facilities would be "owned" by the producers. Several of the comments questioned the Commission's jurisdiction to prescribe who could or could not "own" those facilities. In response to those comments, the Commission has recast its policy by deleting references to "ownership" of the facilities, focusing the policy instead on the "financial responsibility" for the conditioning facilities in the sense of which parties ought to bear the burdens of certain conditioning costs. As so recast, the Commission's policy is not necessarily premised on "ownership" of those facilities by any particular parties or entities, or by any combination thereof.

Accordingly, it would be premature to attempt to resolve at this time what "conditions" should be imposed in connection with "ownership" of the conditioning facilities, or even who might or might not have jurisdicition to impose such conditions. Those issues ought to be deferred until such time as more facts are available as to the contemplated nature and ownership of the facilities.

3. *Carbon Dioxide Standards*. In response to certain comments regarding the Commission's April 6, 1979, Notice of Proposed Rulemaking in Docket No. RM78-12,[55] the Commission ordered [56] the submission of further information and comments regarding the appropriate carbon dioxide content standard for natural gas entering the ANGTS, along with information regarding the impact of such standard on the distribution of costs between the conditioning and transportation functions. However, the Commission specifically reserved any "* * * determination of whether such studies are relevant and material

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limited judicial review provisions contained in section 10 of the ANGTA. Thus, Sohio argues that judicial review of Commission action taken under the substantive law of NGPA must be a review pursuant to the provisions of section 506 of that Act, because, as a subsequently enacted law, the NGPA must supercede the provisions of section 10 of ANGTA. Reply Comments of Sohio Natural Resources Co. (Docket No. RM79-19) (filed April 3, 1979). Determination of the nature and scope of judicial review applicable to this rulemaking rests with the courts, not the Commission.

[54] These rules may be summarized as follows:

(1) The facility must provide nondiscriminatory access to all producers of natural gas;

(2) Any owner providing capital can unilaterally obtain expansion of the gas conditioning facility;

(3) An ownership share must be made available to all parties wishing to use the facilities, and this rule for ownership should be promulgated prior to construction; and

(4) Ownership must be revised on a regular basis according to use.

See Comments of the United States Department of Justice (Docket No. RM79-19) (filed March 19, 1979).

[55] Determination of Incentive Rate of Return, Tariff and Related Issues for the Alaska Natural Gas Transportation System, Docket No. RM78-12. "Initial Comments of the State of Alaska" at 6-7 (May 4, 1979), and "Comments of Sohio Natural Resources Company on Notice of Proposed Rulemaking Issued April 6, 1979" at 2 (May 4, 1979).

[56] Docket No. RM78-12, and this proceeding. "Order Requesting Further Submission of Data, Views, and Comments" (May 16, 1979).

to the issues to be resolved in Docket No. RM79–19." (May 16, 1979 Order at 4.) Based on the comments received, we believe that a determination of the appropriate carbon dioxide standard is not required for our consideration of Docket No. RM79–19. The resolution of that issue is left to further order under Docket No. RM78–12.

4. *Procedural Due Process.* This rulemaking was first noticed for comment on February 2, 1979. By that notice, comments were required to be filed by March 5, 1979, and reply comments were to be filed by March 19, 1979. Upon consideration of a motion by Sohio Natural Resources Company, the Commission extended the deadlines for filing initial and reply comments to March 19, 1979, and April 2, 1979, respectively.

After the close of the last filing date, the Commission issued two additional requests for comments and data. The first, soliciting information as to the proper carbon dioxide standard for the ANGTS and entitled "Order Requesting Further Submission of Data, Views, and Comments," was issued May 16, 1979. Initial data was to be submitted by June 1, 1979, and comments on the data were to be filed by June 15, 1979. By Notice issued June 14, 1979, the latter comment period was extended to June 25, 1979. This extension, granted in response to a motion filed by the State of Alaska, was made applicable only to that party. The second additional request for comments, a "Notice Inviting Comments" on a recently received special study reviewing Alaska Natural Gas Transportation System issues, and on two producer contracts for the sale of Prudhoe Bay gas that had been recently filed with the Commission, was issued May 31, 1979. Comments on these three items were to be filed by June 15, 1979. Upon consideration of motions filed by Exxon and Sohio, that comment period was extended to June 22, 1979.

Throughout the course of the proceeding, the Commission received several motions for extension of time to file comments or reply comments. Not all were granted, and those that were granted were for less than the requested times. The Commission is of the opinion that it proceeded properly, given the dual legal mandates of providing adequate time for reasoned comments [57] while acting as expeditiously as possible with respect to action touching upon the ANGTS, 15 U.S.C. 719g(a).

In all, 16 comments and 7 reply comments were received in response to the initial notice.[58] Besides the report on carbon dioxide submitted by Atlantic Richfield,[59] the Commission received a total of 10 comments in response to its notice inviting comment on carbon dioxide standards.[60] Finally, a total of 7 comments were received in response to the Commission's issuance of the special study and producer contracts.[61] This response supports our opinion that, while necessarily brief, the comment periods set for this docket were adequate to assure meaningful and reasoned responses.

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[57] *See, e.g.,* Portland Cement Assoc. v. Ruckelshaus, 486 F.2d 375, 392–393 (D.C. Cir. 1973).

[58] Sixteen initial comments were received: Comments of the Public Service Commission of the State of New York (Docket No. RM79–19) (filed March 8, 1979); Comments of Columbia Gas System Service Corporation, (Docket No. RM79–19) (filed March 15, 1979); Initial Comments of the People of the State of California and the Public Utilities Commission of the State of California, (Docket No. RM79–19) (filed March 16, 1979); Comments of Mobil Oil Corporation on the Proposed Rulemaking and Statement of Policy Concerning Production-Related Costs for Prudhoe Gas issued by the Federal Energy Regulatory Commission on February 2, 1979, (Docket No. RM79–19) (filed March 19, 1979); Comments of Panhandle Eastern Pipe Line Company, (Docket No. RM79–19) (filed March 19, 1979); Comments of SOHIO Natural Resources Company Concerning Proposed Rulemaking and Statement of Policy (Docket No. RM79–19) (filed March 20, 1979); Comments of Texaco, Inc. (Docket No. RM79–19) (filed March 19, 1979); Comments of Exxon Corporation (Docket No. RM79–19) (filed March 19, 1979); Comments of the State of Alaska (Docket No. RM79–19) (filed March 19, 1979); Comments of United States the Department of Justice (Docket No. RM79–19) (filed March 19, 1979); Comments of Foothills Pipe Lines (Yukon) Ltd. on Notice of Proposed Rulemaking and Statement of Policy (Docket No. RM79–19) (filed March 19, 1979); Initial Comments of the Federal Energy Regulatory Commission Staff (Docket No. RM79–19) (filed March 19, 1979); Comments of Atlantic Richfield Company on the Proposed Rulemaking and Statement of Policy concerning Production-Related Costs for Prudhoe Gas issued by the Federal Energy Regulatory Commission on February 2, 1979, (Docket No. RM79–19) (filed March 19, 1979); Letter to Mr. Plumb, Secretary to the Commission, from Earth Resources Company of Alaska (Docket No. RM79–19) (dated February 28, 1979); Comments of Northwest Pipeline Corporation (Docket No. RM79–19) (filed March 19, 1979); Comments of Pacific Interstate Transmission Company (Docket No. RM79–19) (filed March 10, 1979). Seven reply comments were filed as well: Reply Comments of the State of Alaska (Docket No. RM79–19) (filed Apr. 3, 1979); Reply Comments of Atlantic Richfield Corporation on the Proposed Rulemaking and Statement of Policy Concerning Production-Related Costs for Prudhoe Gas Issued By the Federal Energy

It is with respect to the last request for comments, the Notice which circulated for comment the special study on ANGTS issues and the producer contracts, that questions have been raised concerning due process.[62] The gravamen of these allegations was that the Commission provided inadequate time to comment. This lack of adequate time was attributed in part to the short comment period, but particularly to the late release of a large amount of background information on the study, in response to information requests by certain parties.[63] The Commission is of the opinion that these objections are groundless. First, while it is incumbent

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Regulatory Commission on February 2, 1979 (Docket No. RM79-19) (filed Apr. 2, 1979); Reply Comments of Exxon Corporation (Docket No. RM79-19) (filed Apr. —, 1979); Reply Comments of the Federal Energy Regulatory Commission Staff (Docket No. RM79-19) (filed Apr. 3, 1979); Reply Comments of Northwest Pipeline Corporation (Docket No. RM79-19) (filed Apr. 2, 1979); Reply Comments of Sohio Natural Resources Company (Docket No. RM79-19) (filed Apr. 3, 1979); Reply Comments of Texaco, Inc (Docket No. RM 79-19) (filed Apr. 4, 1979).

[59] Ralph M. Parsons Co., *February 1979 Supplementary Report CO$_2$ Specifications Study: Sales Gas Conditioning Facilities Prudhoe Bay, Alaska,* (1979) (submitted by Atlantic Richfield Company in Docket Nos. RM78-12, RM79-19, June 8, 1979).

[60] Comments of Alaskan Northwest Natural Gas Transportation Company and Northern Border Pipeline Company (Docket Nos. RM78-12, RM79-19), (filed June 1, 1979); Comments of Atlantic Richfield Company in reponse to the Order Requesting Further Submission of Data, Views and Comments issued May 16, 1979 (Docket Nos. RM78-12, RM79-19) (filed June 1, 1979); Comments of Sohio Natural Resources Company on Order Requesting Further Submission of Data, Views, and Comments issued May 16, 1979 (Docket Nos. RM78-12, RM79-19) (filed June 1, 1979); Letter of June 15, 1979 by Northwest Alaskan Pipeline Company to Kenneth Plumb, Secretary to the Commission (Docket Nos. RM78-12, RM79-19) (filed June 15, 1979); Reply Comments of Atlantic Richfield Company (Docket Nos. RM78-12, RM79-19) (filed June 15, 1979); and Reply Comments of Exxon Corporation (Docket Nos. RM78-12, RM79-19) (filed June 15, 1979). In addition four other comments were submitted and reviewed after the June 15th date. These included the comments of Alaska, submitted under the Commission's action to permit late filing, Reply Comments of the State of Alaska (Docket Nos. RM78-12, RM79-19) (filed June 25, 1979); Reply Comments of SOHIO Natural Resources Company (Docket Nos. RM78-12, RM79-19) (received June 22, 1979); comments of Natural Gas Pipeline Company of America (Docket Nos. RM78-12, RM79-19) (received July 3, 1979); additional comments of the Federal Energy Regulatory Staff (Docket Nos. RM78-12, RM79-19) (received June 26, 1979).

[61] Further Comments on the State of Alaska (Docket No. RM79-19) (filed June 22, 1979); Comments of Atlantic Richfield Company Concerning Staff Study Entitled "A Review of Alaska Natural Gas Transportation System Issues" (Docket No. RM79-19) (filed June 22, 1979); Comments of Columbia Gas Transmission Corporation (Docket No. RM79-19) (filed June 22, 1979); Limited Comments of Exxon Corporation Regarding the ICF Study on Alaska Natural Gas Transportation System Issues and Prudhoe Bay Gas Sales and Purchase Agreements (Docket No. RM79-19) (filed June 22, 1977); Comments of the People of the State of California and the Public Utilities Commission of the State of California (Docket No. RM79-19) (filed June 22, 1979); Comments of SOHIO Natural Resources Company concerning May 1979 Report by ICE (sic) Incorporated and Gas Sale and Purchase Agreements (Docket No. RM79-19) (filed June 22, 1979); Additional Comments of the Federal Energy Regulatory Commission Staff (Docket Nos RM78-12, RM79-19) (received June 26, 1979).

[62] *See, e.g.,* Comments of Atlantic Richfield Company Concerning Staff Study Entitled "A Review of Alaska Natural Gas Transportation System Issues" at 2, n.2 (Docket of Exxon Corporation Regarding the ICF Study on Alaska No. RM79-19) (filed June 22, 1979); "Limited Comments Natural Gas Transportation System Issues and Prudhoe Bay Gas Sale and Purchase Agreements" at 2-4 (Docket No. RM79-19) (filed June 22, 1979).

[63] On June 6, 1979 and again on June 11, 1979, attorneys for the Exxon Corporation petitioned the Commission under § 3.102 and 1.36 of its regulations for the release of certain information concerning the study issued for comment. June 6, 1979 letter of Michael J. Manning and Patrick J. Keeley to John Adger, Director of the Commission's Alaska Project Office (Docket No. RM79-19) (filed June 7, 1979); June 11, 1979 letter of Michael J. Manning to and Patrick J. Keeley to John Adger Director (Docket No. RM79-19) (filed June 12, 1979). Responses to these requests were made on June 8, 15, 18 and 20, 1979, with copies served on all parties of record in Docket No. RM79-19.

upon the Commission to provide an adequate time to respond by comments, this requirement is tempered by the ANGTA's mandate for expedition. Second, while mildly relevant, neither the report nor the two contracts were materially relied upon by the Commission in promulgating this rule. Moreover, neither the study nor the contracts had to be noticed; the Commission could merely have made them a part of the public record in this proceeding.

Thus, the Commission believes that the procedures it has followed fully and properly comply with the notice and comment process. Nevertheless, in an abundance of caution, and to eliminate any lingering doubts, the Commission will afford the parties an additional opportunity to comment on the study and the background materials circulated in response to the information requests. In issuing this rule, the Commission has provided for an opportunity to petition for rehearing. Parties who wish to submit additional comments on the study and its background material may do so in conjunction with any petition for rehearing.

Finally, we note that on July 12, 1979, the Commission circulated to all parties in Docket No. RM79-19, copies of documents voluntarily supplied to counsel for the State of Alaska in response to a Freedom of Information Act request that has become the subject of litigation.[64] The Commission has not relied on that material in any way in the preparation of this Order. Nevertheless, inasmuch as those documents were circulated subsequent to the close of the comment period (as extended), and inasmuch as the Commission is permitting limited additional comment in conjunction with petitions for review, the Commission will also permit all parties to include in those comments any additional comments they may wish to make with respect to the material circulated in response to Alaska's Freedom of Information Act request.

Further Proceedings

The Commission is making this rule effective 60 days from the date of its issuance. The Commission will permit petitions for rehearing to be filed within 30 days of the date of issuance. Such petitions may include certain additional comments, as described above.

Pursuant to the mandate of section 502(b) of the Natural Gas Policy Act, the Commission will provide an opportunity for oral presentations prior to the effective date of this Order. That opportunity will occur subsequent to the date by which petitions for rehearing must be filed and prior to the Commission's resolution of such petitions. An appropriate notice will be issued, advising all interested persons of the time and place of the oral presentations.

Because this rule is issued *inter alia* pursuant to ANGTA, the Commission believes that it has an important responsibility to resolve all issues attendant to the rule as promptly as possible. Final agency action to permit prompt judicial review should occur as soon as reasonably practicable. Likewise, agency action implementing the rule should also proceed as promptly as possible. Therefore, we are structuring the petition procedure so as to permit judicial review (if any) on the rule to commence within 60 days of the issuance of this Order, while simultaneously inaugurating proceedings under the Order.

Accordingly, any party that wishes to file an application for review under § 271.1106 of the Commission's regulations, and that also wishes to file a petition for rehearing of this Order, may cast its petition for rehearing, in the alternative, as an application for an adjustment under section 502(c) of the NGPA. In the event that such petition for rehearing is denied, the Commission, on its own motion, will then immediately proceed to consider the section 502(c) application. Such alternative applications accompanying petitions (or the petitions themselves) should be written in conformity with the Commission's regulations governing such applications, § 1.41 of the Commission's rules of practice and procedure. Should a denial of a petition for rehearing require such consideration, the Commission will review the application under the same rules as govern all such applications except that the 150-day determination period for staff review (§ 1.41(i)(3)) shall, for purposes of this order only, be shortened to 60 days. The Commission waives that provision of its regulations in order to review and decide such applications as quickly as possible.

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[64] The request was made by attorneys on behalf of the State of Alaska, March 5, 1979, letter of Mr. Robert H. Loeffler to the Commission's Director of Public Information. The case is State of Alaska v. FERC, No. 79-1329 (D.C.D.C. filed May 15, 1979).

Findings

For the reasons set forth above, the Commission finds:

(1) That the granting of an allowance under section 110 of the NGPA to the first sellers of natural gas produced at Prudhoe Bay, Alaska for transport through the ANGTS is an action related to the construction and initial operation of the ANGTS.

(2) That such allowances should not be granted except for costs incurred in the removal of carbon dioxide from a level of three percent by volume to a level of less than three percent by volume.

(3) That allowance for any production-related cost may, on future consideration, be necessary to prevent or alleviate special hardship, inequity, or an unfair distribution of burdens, and that provision should be made for such allowances pursuant to the procedures of section 502(c) of the NGPA.

(4) That there is a rebuttable presumption that costs incurred by transporters or shippers to condition natural gas (except for carbon dioxide removal below three percent) for transportation through the ANGTS are costs that were not prudently incurred.

(5) That the actions taken under this Order are in the public interest, and are necessary and appropriate for the proper adminstration of the Natural Gas Policy Act, the Natural Gas Act, the Alaska Natural Gas Transportation Act, and the President's *Decision* as adopted by the Congress.

Orders

Upon these findings and for the reasons set forth above, the Commission orders:

(1) That the regulations of the Commission be amended as set forth below, such amendments to become effective 60 days from the date of issuance of this Order.

(2) That parties to Docket No. RM79-19 may file petitions for rehearing of this rule within 30 days of the date of issuance of this order, pursuant to the procedure set forth in § 1.34 of the Commission's rules of practice and procedure. Such petitions may include views, data and comment with respect to the background materials that were circulated to the parties in response to information requests submitted by Exxon, and in response to the Freedom of Information Act request submitted by the State of Alaska, which materials were circulated to the parties shortly prior to, or subsequent to, the close of the comment period.

(3) That petitions for rehearing may be accompanied by, or drafted in the alternative as, an application for an adjustment pursuant to section 502(c) of the Natural Gas Policy Act and § 271.1106 of the regulations. Such applications under § 271.1106 are to be made in conformance with the requirements of § 1.41 of the Commission's rules of practice and procedure.

(4) That in the event of a denial of any petition for rehearing under this Order which is drafted in the alternative as, or accompanied by, an application for an adjustment pursuant to section 502(c) of the Natural Gas Policy Act, the Commission will, on its own motion, immediately proceed with consideration of such application. In considering such application, the Commission will be bound by the procedures of § 1.41 of its regulations except that the applicable

"determination period" for staff review shall be 60 days commencing from the date that the petition for rehearing is denied.

(5) The Commission will provide an opportunity for oral presentations, subsequent to the date for filing petitions for rehearing and prior to the resolution of such petitions. A notice will be issued in sufficient time to provide interested parties knowledge of the time and place for such presentation and the procedures to be followed.

(Department of Energy Organization Act, Pub. L. No. 95–91, 91 Stat. 565, E.O. 12009, 42 FR 46267 (Sept. 15, 1977); Natural Gas Act, *as amended*, 15 U.S.C. §§ 717, *et seq.*; Alaska Natural Gas Transportation Act, 15 U.S.C. § 719(g); President's *Decision and Report to Congress on the Alaska Natural Gas Transportation System*, H.J. Res. 621, Pub. L. No. 95–158, 91 Stat. 1268 (1977); Natural Gas Policy Act of 1978, Pub. L. No. 95–621, 92 Stat. 3300 (1978).

In consideration of the foregoing, Part I, Subchapter A, Chapter I of Title 18 and Part 271, Subpart K of Title 18 are amended as set forth below, effective 60 days from the date of issuance.

By the Commission. Commissioner Sheldon, dissenting, filed a separate statement appended hereto.

Kenneth F. Plumb,
Secretary.

[¶ 30,081]

44 F.R. 52179 (September 7, 1979)

18 CFR Parts 157, 281, 284, Subchapter H, and Subchapter I

[Docket No. RM79–75; Order No. 46]

Sales and Transportation of Natural Gas

Issued: August 30, 1979.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is amending and making final certain of the interim regulations published December 1, 1978, concerning the transportation of natural gas by interstate pipelines on behalf of intrastate pipelines and local distribution companies.

EFFECTIVE DATE: October 1, 1979.

FOR FURTHER INFORMATION CONTACT: Robert C. Platt, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357–8433.

Final Part 284 Regulations Under the Natural Gas Policy Act of 1978; Order amending Part 284 and issuing Subparts A, B, C, and E as final regulations (Issued August 30, 1979).

I. Background

On December 1, 1978, the Federal Energy Regulatory Commission (Commission) issued interim regulations implementing the Natural Gas Policy Act of 1978 (NGPA) (43 F.R. 56448). Subparts A, B, and D of Part 284 of the interim rule implemented sections 311(a) and 312 of the NGPA. In the final rule, Subparts B, C, and E implement these sections.[1]

Section 311(a)(1) allows the Commission to authorize the transportation of natural gas by interstate pipleines on behalf of intrastate pipelines and local distribution companies (subpart B of the final rule). Section 311(a)(2) allows the Commission to authorize the transportation of natural gas by intrastate pipelines on behalf of interstate pipelines and local distribution companies served by interstate pipelines (subpart C of the final rule). Section 312 allows the Commission to authorize the assignment of natural gas by intrastate pipelines to interstate pipelines or local distribution companies (subpart E of the final rule).

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[1] Because certain rules of general applicability were thought to be most conveniently placed at the beginning of Part 284, Subpart A of the interim rule is now issued as Subpart B, Subpart B has become Subpart C, etc. Subpart F has remained as Subpart F.

Oral comments were made at public hearings on these subparts, and written comments were received. Several suggestions made in the comments have been incorporated in the final rule.

II. Discussion of Comments and Amendments

1. *What are the jurisdictional consequences of performing activities authorized by the Commission under sections 311 and 312 of the NGPA?*

Many parties requested clarification of the jurisdictional consequences of performing section 311 or 312 activities. Most simply requested that the regulations specifically reflect the language of section 601. It is our conclusion that sales, assignments and transportation services authorized by the Commission under sections 311 or 312 are clearly exempted from the Commission's Natural Gas Act (NGA) jurisdiction by the operation of section 601(a) of the NGPA.[2] The Commission has reflected this statutory language in the final rule in § 284.3 (a) and (b).

However, the NGPA is silent on the jurisdictional consequences of participating in the construction and operation of the facilities necessary to effectuate transportation authorized by the Commission under section 311(a). It is our view that a facility is not subject to NGA jurisdiction if it is used exclusively for transportation authorized under section 311(a);[3] thus, no certificate is required by section 7 of the NGA. This position is set out in the final rule in § 284.3(c).

One comment requested that if authorization under section 311(a) is found not to exist, the parties to such a transaction be allowed to cease operations without having NGA jurisdiction attach if the transaction was entered into in good faith. This suggestion is rejected. Section 601 removes the Commission's NGA jurisdiction from a transaction otherwise subject to NGA jurisdiction only if the transaction is "authorized" by a Commission rule or order. Section 601 does not remove the Commission's NGA jurisdiction from a transaction otherwise subject to NGA jurisdiction if the parties erroneously, in good faith, believed they had section 311(a) authorization, when in fact such authorization did not exist. However, the Commission will consider the transporter's good faith, and the absence of willfull misconduct, in determining whether continuing jurisdiction attaches.

Another related issue is the extent of NGA jurisdiction over those transactions which could go forward under section 311(a)(1), but for some reason the interstate pipeline desires to obtain a certificate under section 7 of the NGA. The Commission will not issue such certificates unless the reasons for not transporting pursuant to section 311(a)(1) are extraordinary. It shall be our policy that authorization under section 311(a)(1) of the NGPA should be utilized wherever possible, without resort to certification under section 7 of the NGA. (*See*, ONG Western, Inc., Docket No. CP79–133.)

2. *Self-execution:* A. *Resale requirement.*—Although the issue was not addressed in the comments, the Commission has decided to limit the

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[2] Throughout Part 284, language referring to Commission authorization has been added, to emphasize the fact that transactions can take place only with Commission authorization, whether or not that authorization entails prior approval of the transaction.

[3] If the facility also transports natural gas in interstate commerce, not authorized by the Commission under section 311(a), NGA jurisdiction attaches to the facility. However, the mere fact that the volumes of natural gas were transported under section 311(a) for one part of the transportation arrangement does not render all the facilities which transport such gas to be non-jurisdictional under the NGA. For example, if an interstate pipeline must construct facilities to reach out to connect with an intrastate pipeline system to enable the interstate pipeline to receive into its system supply certain volumes transported by the intrastate pipeline under section 311(a)(2), those interstate pipeline facilities are subject to the Commission's jurisdiction under the NGA because the transportation by the interstate pipeline through those facilities is not authorized under section 311(a)(1); i.e., the transportation by the interstate pipeline is "on behalf" of itself, not any other entity. Thus, it is the nature of the transportation authorization that determines whether facilities used for that transportation are subject to NGA jurisdiction. *See* Natural Gas Pipeline Corporation of America, Docket No. CP79–200.

self-execution of section 311(a) (1) and (2) transportation arrangements to those arrangements in which the final recipient of the natural gas has acquired the natural gas for its system supply and will resell the gas in accordance with its applicable curtailment plan.[4] Sections 284.102(b)(1)(ii) and 284.122(b)(1)(ii) are designed to encourage transportation of gas to be used in system supply by allowing these transactions to occur without prior Commission approval. Thus, Subparts B and C of the final rule do not authorize transportation directly to end-users unless the transportation is specifically approved by the Commission.[5]

In Order No. 30, issued May 17, 1979, (44 FR 30323, May 25, 1979) the Commission promulgated Subpart F of Part 284 to authorize the transportation of natural gas directly to eligible end-users to displace fuel oil. These regulations were, in part, issued pursuant to section 311(a), and are a further exercise of the authority granted to the Commission in section 311(a). Order No. 30 constitutes the only exercise of the Commission's power to grant section 311(a) self-executing authorization for transportation arrangements other than for system supply.

One additional facet to section 311(a)(2) transportation should be pointed out. In order to qualify to transport under section 311(a)(2), the transportation must be performed by an "intrastate pipeline" within the meaning of section 2(16) of the NGPA. However, that definition would seem to require that the prospective section 311(a)(2) transporter be "engaged in natural gas transportation * * * which is not subject to the jurisdiction of the Commission under the Natural Gas Act." If a *new* pipeline company is planned, it would not fit within this literal definition of "intrastate pipeline" until it first engages in transportation. Consequently, the proposed pipeline company could not engage in section 311(a)(2) transportation unless it establishes that it is engaged in nonjurisdictional transportation. It may so establish by obtaining a declaratory order from the Commission that it qualifies as an intrastate pipeline for section 311(a)(2) transportation.[6] The Commission's interpretations procedure under 18 C.F.R. 1.42 is also available for this purpose. However, it should also be noted that if a corporate entity qualifies as an intrastate pipeline under section 2(16) it will retain that identity for its entire system even if it constructs a new portion of its system to be used exclusively for section 311(a)(2) transportation.

B. *Facilities.*—Several comments indicated that the interim rules did not address the question of the cost treatment of facilities. In Docket No. RM79-43 (44 FR 30331, May 25, 1979), the Commission issued interim rules allowing section 311(b) and 312 facilities owned and operated by an interstate pipeline to be authorized under its budget-type certificate. Final rules will soon be promulgated in that docket.

C. *"On behalf of".*—It is our view that the phrase "on behalf of", which is found in both sections 311(a)(1) and (2), should be broadly construed to give the Commission the necessary flexibility to carry out the Congressional objective of integrating the intrastate and interstate markets.[7] Obviously, some nexus is required between the transporter and the party on whose behalf the transaction will be conducted. That nexus may be an agency relationship, or having title to the transported gas reside, during the transaction, in the party on whose behalf the transportation is conducted. For those parties who wish to determine if a particular transaction meets the statutory requirements of section 311, the Commission may be requested to provide interpretations pursuant to section 502(c) of the NGPA.[8] See the Interim Regulations issued on August 7, 1979, in Docket No. RM79–65 (44 FR 48171, August 17, 1979) for the procedures for providing interpretations and interpretative rules under the NGPA.

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[4] Of course, the requirement of resale will not include those volumes utilized by the final recipient of the gas for compressor fuel or line loss.

[5] The Commission wishes to scrutinize such transactions except as otherwise authorized by our regulations.

[6] See the Declaratory Order issued in Texas Sea Rim Pipeline, Inc., Docket No. CP79-117, on February 16, 1979.

3. *Interstate pipeline transportation.*—Several comments requested that the regulations be amended to authorize transportation services between interstate pipelines without prior Commission approval. Some comments expressed the opinion that the authority to do so lies in the NGA; that NGA certification can be dispensed with, or "blanket" authorization can be granted; or that temporary authorization could be granted under expedited procedures, which later could be changed to permanent certification.

These suggestions are rejected. Section 7 of the NGA requires certificates of public convenience and necessity for transportation arrangements between interstate pipelines. The NGPA does not supersede these requirements, although the Commission may examine, at a future date, the desirability of issuing "blanket" section 7(c) transportation certificates.

One comment suggested that interstate pipelines should be *required* to transport gas for local distribution companies, at least on a best efforts basis, up to the local distribution company's daily contract demand quantity. This comment indicates that mandatory transportation service is necessary to encourage local distribution companies to develop additional natural gas resources.

There is no indication in section 311(a)(1), or in its legislative history, that interstate pipelines were intended to be required to render transportation services. Indeed, section 602(b)(2) specifically states that no person shall become a common carrier by reason of section 311(a) transportation. Thus, the Commission is without authority to require transportation services by interstate pipelines solely by reason of section 311(a)(1).

4. *Rates and Charges for Interstate Pipelines.*—Two comments suggested that the allowance of one cent per Mcf for out-of-pocket expenses is insufficient to cover the costs of participating in section 311(a)(1) transportation services. The Commission believes that the one cent allowance covers the level of out-of-pocket expenses normally incurred by interstate pipelines in rendering transportation service through its otherwise unused capacity. Later, if it becomes apparent that interstate

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[7] The report of the Ad Hoc Committee explained the purpose of these sections: The amendment facilitates development of a national natural gas transportation network without subjecting intrastate pipelines, already regulated by State agencies, to FPC regulation over the entirety of their operations. Instead the intrastate pipelines are immunized from State or Federal regulation as common carriers and from FPC regulation under the Natural Gas Act. The intrastate pipelines are only subjected to FPC regulation under this legislation to the extent the intrastate pipeline is involved in an authorized sale of natural gas to interstate pipelines or an authorized transportation of natural gas on behalf of interstate pipelines. Other operations of an intrastate pipeline are not intended to be subject to FPC regulation by reason of this amendment. (H.R. Rept. No. 543, 95th Cong. 1st Sess. 45 (1977).)

[8] For example, an intrastate pipeline selling natural gas to an interstate pipeline under section 311(b) may contract with another interstate pipeline to transport the gas to the interstate pipeline purchaser, with title passing at the point of delivery to the purchaser. The intermediary interstate pipeline would be able to transport the gas under section 311(a)(1) authorization. Conversely, if the interstate pipeline purchaser contracted for the transportation and if title passed to the purchaser at the point of delivery to the intermediary transporting interstate pipeline then, absent other evidence that the transaction was on behalf of an intrastate pipeline or local distribution company, the nexus would not be present and section 311(a)(1) authorization would not be available.

pipelines can consistently show that the one cent allowance is insufficient, the limit can be changed. There should be no hardship as a result of the one cent allowance, because the allowance is merely a presumption that there will be out-of-pocket expenses of one cent per Mcf. If there are in fact greater expenses, the interstate pipeline will be able to recover them upon a showing to the Commission.

Other comments objected to the requirement that revenues in excess of out-of-pocket expenses must be credited to Account 191. In particular, one commenter stated that the requirement to credit Account 191 is inconsistent with setting rates based on test periods. The commenter argued that since the amount of gas transported may vary during the period a rate is in effect, there is no basis to assume that section 311(a)(1) service will result in more total revenues than the rate was designed to provide. The commenter stated further that, due to inflation, even if there is an increase in revenues there is no basis to assume that the increase will not be offset by increased costs. The Commission believes that the proper forum to address these problems is the interstate pipeline's next rate case. Consequently, the procedure for treating section 311(a)(1) revenues will not be changed.

Several comments suggested that the "out-of-pocket" limitation would not induce interstate pipelines to participate in section 311(a)(1) transactions, because there is no incentive for interstate pipelines to participate. However, the Commission is concerned that if an incentive is provided for section 311(a)(1) transactions, that very incentive may operate to make these transactions so attractive that they would have a deleterious effect on other short term transportation arrangements, as well as purchases for system supply. The Commission is studying the relationship between the rate design of all transactions which can be used to achieve the objective of opening up intrastate supplies of natural gas to the interstate market. At the completion of that study, the Commission will re-examine the necessity of providing an incentive for section 311(a)(1) transactions. In the meantime, the flow back requirement will remain unchanged.

It was apparent from these and other comments that the flow back procedures in § 284.103(d) were confusing. Accordingly, this section has been redrafted to more clearly express the intention that the one cent allowance is optional with the transporting interstate pipeline. If the interstate pipeline chooses, it may forego the allowance and demonstrate its out-of-pocket expenses to the Commission. The Commission will not require a flow back of any amount the interstate pipeline has established as representative of out-of-pocket expenses.

One comment objected to the flow back procedure of the rule becaue the flow back is system-wide even for those interstate pipelines that do not set their rates on a system-wide basis. In such a situation, it was stated that certain customers of such an interstate pipeline will receive flow back credits for transportation costs that the customers have never incurred. Although this recommendation may be appropriate in certain rare situations, the Commission feels that the general rate proceeding for the interstate pipeline is the proper place for this issue to be addressed. To attempt to address this specific refund question in this regulation would be difficult to do, given the unique fact situations involved.

One comment requested that the regulations contain a provision to set a uniform standard for determining fuel use and line loss, and a prohibition disallowing an interstate pipeline from requiring a shipper to sell to it any portion of the shipper's transportation volumes. Adopting these provisions would tightly control the terms of section 311(a)(1) contracts, and would have the effect of requiring all section 311(a)(1) compensation to be paid in a form that could be flowed back to the pipeline's customers. The Commission feels that any possible advantages to the pipeline's customers in adopting this approach would be offset by the disadvantages of strait-jacketing the parties into contracts which may be unrealistic for a particular set of circumstances. Given the importance of maximizing participation in section 311(a)(1) transactions, these limitations will not be adopted.

The Commission has amended § 284.103(c)(2) to indicate that comparison can be made to only those rate schedules filed by the interstate pipeline transporting pursuant to section 311(a)(1). Rate schedules filed by another interstate pipelines cannot be used.

5. *Terms and Conditions Imposed by the Commission on Section 311(a) Transactions.*—Several comments suggested that the two-year term is too short. One suggested that an extension past two years be self-executing. Another recommended that the two-year review by the Commission (which is predicated on the need to examine pipeline transportation capacity) be replaced with a program limiting transportation on a priority basis: section 311(a)(1) transportation volumes in excess of contract demand quantities would receive the lowest priority, and section 311(a)(1) volumes within contract demand quantities would receive the next to lowest priority. Yet another comment suggested that "best efforts" section 311(a) transportation would solve the capacity problem.

The first suggestion has already been met in § 284.105. Extensions of two years are self-executing unless the Commission decides that an extension is not in the public interest.

The other commenters' suggestions are rejected, because the Commission continues to believe that it is appropriate to review long-term transportation arrangements in order to allow an evaluation of the impact of such arrangements on the capacity of interstate pipelines to meet the needs of its customers.

Other comments suggested (1) the term "detriment or disadvantage" in § 284.104(a) be clarified; and (2) the word "prospectively", which was used in §§ 284.104(c), 284.124(c), 284.145(d), and 284.164(c) of the interim rule, be clarified to indicate that executed contracts would not be modified by future Commission action.

The phrase "detriment or disadvantage" is sufficiently clear. The Commission intends this phrase to include actual curtailment of natural gas service as well as any other adverse effect upon an existing customer or end-user.

The term "prospectively" is also sufficiently clear. Under certain circumstances the Commission may promulgate additional terms and conditions which establish requirements for future deliveries under contracts entered into before the promulgation of the additional requirements. Of course, the parties to the contract may provide for the termination of the contract in the event of a changed regulatory framework. In view of the fact that each transaction authorized under Part 284 should be equally subject to modification by the Commission, §§ 284.104(c), 284.124(c), 284.145(d), and 284.164(c) have been deleted and a new § 284.5 added to replace them.

One comment requested that a procedure be implemented whereby an intrastate pipeline could secure temporary authorization, pending final Commission approval, to commence long-term transportation on behalf of interstate pipelines and local distribution companies. Since an intrastate pipeline can arrange for short-term transportation without Commission action, this comment's request has already been met. During the two-year self-implementing period, the intrastate pipeline can apply for long-term approval.

6. *Rates and Charges for Intrastate Pipelines.*—One commenter expressed concern that the amount required to recover all "service" costs listed in § 284.123(b)(1)(i)(A) would be included in the rates authorized by the regulation. Since § 284.123(d)(1) presumes that rates set in accordance with § 284.123(b)(1) are fair and equitable, this concern is unfounded.

Several comments suggested that an intrastate pipeline be able to base its rate on the comparable tariffs of interstate pipelines on file with the Commission. This suggestion is rejected. It would be unreasonable to allow an intrastate pipeline to charge a rate based on the tariff of an interstate pipeline system designed for natural gas transportation of much larger volumes over much larger volumes longer distances. The costs of operation of intrastate pipelines and interstate pipelines are simply not comparable. Intrastate pipelines will be reasonably compensated under the present regulations.[9]

One comment suggested that a pipeline without a comparable tariff on file with a state regulatory agency be allowed to file one, and be able to use that tariff to set its section 311(a)(2) transportation rate, pending the approval of the tariff by the state regulatory agency. This suggestion is also rejected. The intent of the regulations is to set section 311(a)(2) rates by reference to tariffs applicable to other intrastate transportation; absent such a tariff the Commission will set the rate. It would be unwise for the Commission to delegate to a state regulatory agency the power to set the rate to be charged to an interstate pipeline for section 311(a)(2) transportation. The state agency may use different criteria for setting a section 311(a)(2) interstate rate than it would in setting intrastate rates, since its concerns would necessarily be different in the two situations. The final rule in § 284.123(b)(1)(ii) has been amended to make clear that only a "then effective" tariff filed by the transporting intrastate pipeline may be used for comparison.

The words "then effective" refer to the point in time of the deliveries of the natural gas. Thus, if the contract permits, an intrastate pipeline can raise or lower its rates after the transaction is begun, if the applicable tariff rate is changed by the appropriate state regulatory agency. Of course, as stated above, the tariff must be of general applicability, i.e., it must apply to city-gate intrastate service, and it must be the tariff under which the transaction was begun.

Another commenter suggested that a rate set by Commission order for a specific transaction take precedence over any different rate that could be derived from one of the approved formulas. This suggestion has been adopted in § 284.123(b)(2). Specific Commission action in regard to a particular transportation service overrides a rate determined by a formula set out in the regulations.

This commenter also requested the rule be amended to specify that the presumption regarding the treatment of revenues in § 284.123(c) applies only to *future* rate proceedings. This revision is unnecessary; the regulation clearly indicates the presumption applies only to future proceedings.

A state regulatory agency has concluded that the presumption contained in § 284.123(c) impermissibly reaches into the rate-making jurisdiction of the state agency and thus should be deleted. The presumption merely reflects an assumption on the part of the Commission that a state regulatory agency will not ignore the intent of Congress to prevent double recovery for section 311(a)(2) transportation arrangements.[10] Thus, the rule will not be changed.

Another commenter requested that § 284.123(c) be amended to clarify the Commission's intention that it does not require the state agency to investigate each section 311(a)(2) transaction. Such investigations are not required under § 284.123(c). Indeed, it would be impermissible for the Commission to demand that they be made.

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[9] Section 311(a)(2)(B)(i) requires intrastate pipeline rates to "not exceed an amount which is reasonably comparable to the rates and charges which interstate pipelines would be permitted to charge for providing similar transportation service." Our regulations at §§ 284.123 and 284.001(b) meet this requirement by requiring section 311(a)(2) transportation rates be established on a cost-of-service basis, as are interstate pipeline rates.

[10] See p. 109 of the Joint Explanatory Statement of the Committee on Conference.

This commenter further requested an amendment to § 284.123 to provide that there would be no refund liability on the participants to a section 311(a)(2) transaction if a rate set in good faith was later determined not to be "fair and equitable." The Commission cannot accept this position. Accordingly, a specific refund obligation has been included in the final rule in § 284.2(a) for amounts in excess of the amounts allowed by the regulations. An interest rate obligation has also been included in § 284.2(b).

One comment suggested that since not all state agencies regulate transportation rates, a transportation rate set by arms-length contractual negotiations should be defined as "fair and equitable." Adopting this suggestion would obviate the need for rate approval by any public body, and is rejected.

Section 284.123(b)(1)(i)(B) has been amended to identify more clearly the allowance upon which an intrastate pipeline may elect to base its rate. Certain state regulatory agencies do not set intrastate transportation rates directly, but rather grant natural gas distributors an allowance to pay for transportation by the intrastate pipeline to the city gate. The rule refers to this allowance.

7. Assignments.—One comment requested that all section 312 assignments be made self-executing. This request will not be granted. The general rule was specifically intended to limit the kinds of gas which can be assigned without Commission approval to that which is sold at a price below the section 102 price. To make the rule completely self-executing would eliminate such restraints.

Two comments requested clarification of the status of severance taxes under section 312 assignments. Specifically, they request that the rule be amended to allow the price to exceed the new gas price to the extent that the excess reflects allowable section 110 charges. One commenter noted that the new gas price limitation will prohibit the assignment of certain stripper well gas, if the price of that gas exceeds the price for new gas. This commenter is correct. At this time, however, the Commission believes that the section 102 price limitation should reflect all costs associated with the natural gas contract to be assigned. Although specific Commission authorization will be required for the assignment of certain natural gas contracts, we feel that some control should be exercised over an assignment in which the assignee pays a total price which exceeds the section 102 price.

A commenter requested that intrastate pipelines assigning natural gas contracts be given an allowance of one cent per Mcf for transportation costs under § 284.164(a); and, if the pipeline can show costs in excess of one cent per Mcf, it should be allowed that also. This suggestion will not be adopted. The rates for the transportation of natural gas by an intrastate pipeline in association with a section 312 assignment is covered by § 284.123, which covers the rates of a section 311(a)(2) transportation. No special treatment is required for transportation in connection with section 312 assignments.

One commenter has detected two citation errors in § 284.164 (a) and (b) which have been corrected.

8. Reporting Requirements.—One commenter states that the data required by § 284.126(d) is unnecessary, except for the information regarding total revenues. The data requirements of § 284.126(d) will be retained in order to give the Commission a complete picture of section 311(a)(2) transactions. Further, this commenter detected a citation error in § 284.126(a)(3)(v)(A) which has been corrected.

A state regulatory agency requested that copies of the filings required by § 284.165 should be sent to the appropriate state regulatory agency and the intrastate pipeline's customers. This proposal has been adopted in part, in § 284.165(a), to keep the state regulatory agency informed. It would be unduly burdensome to require copies to be sent to the customers of the intrastate pipeline.

The following two amendments are made on the basis of the Commission's experience in monitoring these transactions. First, volumes will be required to be reported in MMBtu's rather than Mcf's because MMBtu's are used throughout the NGPA. (See § 284.4(a).) Second, summary reports must be filed within 48 hours of the commencement of the transaction. (See § 284.4(b).) This requirement has been adopted because, at times, there is an urgent need to know what transactions are taking place and this need is not satisfied by the presently existing reporting requirements.

9. *Definitions.*—Section 284.128 of the interim rule (§ 284.1(b) of the final rule) limits the definition of "appropriate state regulatory agency" to mean a state agency which regulates rates and charges for transportation by the intrastate pipeline "on a cost-of-service basis." One commenter indicated that this definition may exclude some state agencies.

This evaluation is correct. Nevertheless the rule will not be changed in regard to rates. If a state agency does not use a cost-of-service basis for rate setting, the intrastate pipeline company should be required to come to the Commission for approval of a "fair and equitable" rate. The cost-of-service requirement does not apply to matters other than rates, such as the surplus gas determination under § 284.163(a). Through this definition, it is assured that all section 311(a)(2) rates will be cost based.

Two other comments requested a definition of "transportation" to include "exchange, backhaul or other method of transportation." Such definition of "transportation" is included in the final rule, in § 284.1(a). A large portion of the transportation authorization under the NGA is actually transportation by displacement or exchange. To include exchange in the definition of transportation would maximize the amount of gas moving into interstate commerce. Conversely, to limit Subpart B and C transportation to the physical movement of gas volumes would minimize the impact of section 311(a). Defining an exchange to be within the definition of transportation does not conflict with section 2(20) of the NGPA (which defines "sale" to include exchange) because an exchange may have aspects of both transportation and a sale.

One electric utility requested a definition of "intrastate pipeline company" to include not only those entities which actually own facilities, but also those which have contracts for the transportation of natural gas. This commenter states that without such a definition, it cannot dispose of natural gas which it has committed itself to purchase, even though it no longer needs the gas due to conversion to alternate fuels. Another commenter requested that those companies which hold NGA section 7(f) exemptions be declared intrastate pipeline companies. The requested definitions relating to intrastate pipeline companies would be in contravention of section 2(16) of the NGPA, and thus cannot be adopted.

III. Public Procedures and Effective Date

The final regulations in Subparts B, C, and E of Part 284 were originally proposed for comment in November, 1978, and issued as interim regulations (as Subparts A, B, and D) on December 1, 1978 (43 FR 56448, Dec. 1, 1978). For 60 days thereafter comments were received and during that period public hearings were held on these regulations. By this process the Commission complied with the provisions of section 502(b) of the NGPA which requires that "[t]o the maximum extent practicable," an opportunity for the oral presentation of data, views, and arguments be afforded for certain regulations under the NGPA. The amendments to Part 284 contained in this order rest upon considerations given to the information received during the above described notice, comment, and hearing process. Accordingly, the Commission finds that further notice and public procedure on these rules is unnecessary and impractical and that good cause exists to dispense with additional notice and procedure, and to make subparts A, B, C, and E of Part 284, effective in 30 days as final regulations. those transactions entered into before the effective date of these final regulations are subject to the revisions but only with respect to deliveries after the effective date. The revisions made herein are merely clarifications of existing Commission policy, with the exception of the reporting requirements.

(Natural Gas Act, as amended, 15 U.S.C. 717, *et seq.;* Natural Gas Policy Act of 1978, 15 U.S.C. 3301, *et seq.;* Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.;* E.O. 12009, 42 F.R. 46267.)

In consideration of the foregoing, Subparts A, B, C, and E of Part 284 of Subchapter I, Chapter I, Title 18, Code of Federal Regulations, are promulgated as final regulations and amended as set forth below. Subparts D and F of Subchapter I, and Part 157 of Subchapter E, Chapter I, Title 18, Code of Federal Regulations, are amended as set forth below, effective 30 days from the date of issuance of this order.

By the Commission.

Lois D. Cashell,
Acting Secretary.

[¶ 30,082]

44 F.R. 53492 (September 14, 1979)

18 CFR Part 270

[Docket No. RM79-78]

Rules Generally Applicable to Regulated Sales of Natural Gas; Interim Interpretive Regulation

AGENCY: Federal Energy Regulatory Commission.

ACTION: Interim Regulation; request for comments.

SUMMARY: The Commission is issuing an interim regulation defining the term "new well" in section 270.102 of its regulations under the Natural Gas Policy Act of 1978. The regulation provides for the situation of non-producing gas wells which were drilled prior to February 19, 1977, and then reopened to greater depths.

DATES: The regulation to be effective September 7, 1979; written comments due by October 22, 1979; oral presentation on October 11, 1979.

ADDRESSES: Written comments to be submitted to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426; Oral presentations to be held in Hearing Room A, Offices of the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C.

FOR FURTHER INFORMATION CONTACT: Carol Lane; Office of the General Counsel, Federal Energy Regulatory Commission, Room 4308-F, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8067.

A. Background

Section 501(b) of the Natural Gas Policy Act of 1978 (NGPA), 92 Stat. 3350, authorizes the Federal Energy Regulatory Commission "to define, by rule, accounting, technical and trade terms" used in the NGPA, so long as such definition is "consistent with the definitions set forth in [the] Act." Pursuant to this authority, the Commission is issuing an interim interpretive regulation defining the term "new well." Our definition incorporates the statutory definition provided in section 2(3) of the NGPA and clarifies this statutory definition to provide for a particular situation not addressed by the statute.

B. Nature of Proposed Regulation

The Commission's decision to issue this interim rule arises from concern with wells spudded prior to February 19, 1977 which applicants are now attempting to qualify as "new wells" in order to meet the initial statutory requirement for a New Onshore Well under section 102(c)(1)(B) of the NGPA.[1] The statutory definition of "new well" in section 2(3) provides that a new well is "any well—

(A) The surface drilling of which began on or after February 19, 1977; or

(B) The depth of which was increased, by means of drilling on or after February 19, 1977, to a completion location[2] which is located at least 1,000 feet below the depth of the deepest completion location of such well attained before February 19, 1977."

This definition does not address a factual situation in which a well was spudded prior to February 19, 1977, but was not completed and never produced prior to that date, i.e., a dry hole. If the dry hole is redrilled and begins production in commercial quantities after February 19, 1977, there does not exist a "completion location" under the statutory definition from which to measure whether the newly completed well meets the 1000-feet-deeper test. Accordingly, a well which falls into this factual situation does not presently qualify as a "new well."

The Commission notes that it was impossible for Congress, when drafting the NGPA, to have foreseen every factual situation which might arise subsequent to its passage. Moreover, it was precisely because Congress envisaged the possibility of gaps in its definitional scheme that it granted the Commission specific authority in section 501(b) to define terms used in the NGPA. Accordingly, pursuant to section 501(b), we are amending § 270.102(b) of our regulations by adding a new subparagraph (13) which defines the term "new well" to mean any well—

(i) The surface drilling of which began on or after February 19, 1977; or

(ii) The depth of which was increased, by means of drilling on or after February 19, 1977, to a completion location which is located at least 1,000 feet below:

(A) The depth of the deepest completion location of such well attained before February 19, 1977, if such well had a completion location; or

(B) If such well had no completion location because it was a dry hole the drilling of which was terminated prior to February 19, 1977, the deepest drilled depth attained in such dry hole.

Termination of drilling may be evidenced by a showing that the drilling rig was not in location on February 19, 1977.

We believe that this definition reaches a result which is consistent both with the definition of "new well" in section 2(3) and with what the Commission believes Congress intended under section 102, i.e., that an incentive price be provided for gas produced under conditions in which the bulk of the production cost was incurred on or after February 19, 1977.

The Commission makes this interim interpretive regulation immediately effective without prior notice and comment.

C. Written Comment Procedures

Any interested person may submit data, views and comments concerning this interim rule. Such comments should be addressed to the Office of the Secretary, Federal Energy Regulatory Commission, 825 N. Capitol Street, N.E., Washington, D.C. 20426, and should not be submitted later than October 22, 1979. An original and 14 copies should be filed with the Commission, and should reference Docket No. RM79-78. Comments should indicate the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. Written comments shall be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 N. Capitol Street, N.E., Washington, D.C., during regular business hours.

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[1] Section 102(c)(1)(B) of the NGPA provides that a "new onshore well" is "any new well which is 2.5 miles or more . . . from the nearest marker well; or any completion location of any new well which is located at a depth at least 1,000 feet below the deepest completion location of each marker well within 2.5 miles . . . of such new well."

[2] "Completion location" is defined in section 2(7) as "any subsurface location from which natural gas is being or has been produced in commercial quantities."

All comments received by October 22, 1979 will be considered by the Commission prior to the promulgation of final regulations in this matter.

D. Public Hearing Procedures

A public hearing concerning this proposal will be held in Washington, D.C. on October 11, 1979, beginning at 9:30 a.m. Any person interested in this proceeding or representing a group or class of persons interested in this proceeding may make a presentation at the hearing provided a written request to participate is received by the Secretary of the Commission prior to 4:30 p.m., on October 4, 1979.

Requests to participate in the hearing should include a reference to Docket No. RM79-*78*, as well as a concise summary of the proposed oral presentation and a number where the person making the request may be reached by telephone. Prior to the hearing, each person filing a request to participate will be contacted by the presiding officer or his designee for scheduling purposes. At least five copies of the statement shall be submitted to the Secretary of the Commission prior to 4:00 p.m., October 10, 1979. The presiding officer is authorized to limit oral presentation at the public hearing both as to length and as to substance. Persons participating in the public hearing should if possible, bring 10 copies of their testimony to the hearing.

The hearing will not be a judicial or evidentiary-type hearing. There will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested person may submit questions to the presiding officer to be asked of persons making statements. The presiding officer will determine whether the time limitations permit it to be presented. If time permits, at the conclusion of the initial oral statements, persons who have made oral statements will be given the opportunity to make a rebuttal statement. Any further procedural rules will be announced by the presiding officer at the hearing. A transcript of the hearing will be made available at the Commission's Office of Public Information.

This interpretive interim regulation is being made effective immediately but shall not become a final regulation until the Commission has had an opportunity to receive oral and written presentation of relevant data, views and arguments.

(Department of Energy Organization Act, 42 U.S.C. 7107 *et seq.* E.O. 12009, 42 FR 46267; Natural Gas Policy Act of 1978, P.L. 95-621, 92 Stat. 3350).

In consideration of the foregoing, Part 270 of Subchapter H, Chapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,083]

44 F.R. 53493 (September 14, 1979)

18 CFR Parts 270, 273, 284

[Docket No. RM77-22]

Natural Gas Policy and Procedures; Final Regulation and Request for Comments

Issued September 10, 1979.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Regulation and Request for Comments.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is promulgating a final rule which (1) ties

the interest rate on carrying charges and refunds to the prime interest rate charged by banks for short-term business loans, (2) requires quarterly compounding of interest on carrying charges and on funds held subject to refund, and (3) reduces the number of reports that must be filed under §§ 35.19a and 154.67 of the regulations. The refund rules will be applicable to all gas producers and pipelines, and electric utilities under the Commission's jurisdiction. In addition, the preamble to the rule sets forth the procedure the Commission will utilize to receive further comments on whether similar regulations should apply to oil pipelines.

DATES: Effective date October 1, 1979. Comments due October 9, 1979.

ADDRESS: Comments to: Kenneth F. Plumb, Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Dennis H. Melvin, Office of the General Counsel, Federal Energy Regulatory Commission, Room 4016A, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357-8581.

or

Clarence Burris, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8106, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357-8033.

I. Introduction

On March 9, 1979 (44 FR 18046, March 26, 1979) the Federal Energy Regulatory Commission (Commission) issued a Notice of Proposed Rulemaking in this docket, proposing to amend §§ 35.19a, 154.38(d)(4)(iv)(c), 154.67, 154.102, and 273.302(e)(i) of Chapter I, Title 18, of the Code of Federal Regulations (C.F.R.), and add a new Chapter XV, Part 1605, Title 49, C.F.R. The amendments proposed to tie the interest rate on carrying charges and refunds to the prime interest rate charged by commercial banks for short-term business loans, require monthly compounding of interest on funds held subject to refund, impose definitive refund obligations on oil pipelines, and reduce the number of reports that must be filed under §§ 35.19a and 154.67 of the regulations. The refund rules proposed would be applicable to all producers, pipelines (gas and oil) and electric utilities under the Commission's jurisdiction.

Comments were invited from interested parties on or before May 23, 1979. Timely comments were received from a large number of parties representing gas producers, gas and oil pipelines, electric utilities, wholesale distributors of gas and electricity (including municipalities and cooperatives), oil shippers, industrial users, and public interest groups.

II. Appropriate Standard for Refund Interest Rates

A. Summary of Comments. The issue which received the greatest number and variety of comments was that concerning the appropriateness of the Commission's proposal to use the prime rate charged by banks for short-term business loans as the standard for setting refund interest rates. All commenters generally supported the primary considerations for establishing a proper rate of interest on refunds, as set forth in the March 9th Notice of Proposed Rulemaking. Specifically, there was a consensus that the interest rate should: (1) provide just compensation for the losses, or costs, imposed upon those who have paid excessive rates; (2) reflect the benefits which were available to companies which collected excessive rates; and (3) not provide incentives for any party to prolong litigation. Opinions varied widely, however, with respect to the weight to be afforded each criterion, and what would constitute a proper measure of both the costs and benefits associated with excessive payments.

Jurisdictional utilities (sellers) believe the Commission's decision should focus on the benefits which accrue to the collecting companies as a result of overpayments. With a few notable exceptions, sellers contend that these benefits are overstated by the prime rate charged by commercial banks for short-term business loans.

The majority of sellers do not disagree that overpayments may be used for investment purposes, or as a substitute for short-term financing. They argue, however, that the return on such investments, and the rate of interest on substitutable short-term financing, are less than the prime rate. In addition, sellers state that prime rate bank loans have several features (*i.e.*, a definite term and amount, lump-sum availability, line of credit required, charges included for a risk premium and other services) which distinguish them from customer-contributed loans.

Most of the standards proposed by the jurisdictional utilities for measuring the appropriate rate of interest on refunds averaged 100 to 200 basis points below the prime rate during comparable periods. Although the most popular suggestion was the rate of interest associated with short-term (90–119 days or 3–6 months) commercial paper, other proposals included:

(1) The rate on 90-day treasury bills;

(2) The composite commercial paper interest rate;

(3) The rate on 3 to 5 year treasury notes;

(4) The rate on 90-day marketable securities;

(5) The average rate on the refunding company's short-term investment portfolio; and

(6) The present 9 percent rate.

Two sellers, on the other hand, indicated that many of the varieties of short-term paper noted above are not available to all jurisdictional sellers. They argued that the usual term of commercial paper (3–6 months) has little or no correlation with the time period during which refundable amounts are held (usually a year or more). Thus, despite the uncertainty as to when refunds may be required, funds subject to refunds can affect the timing and issuance of long-term borrowing as well as short-term credit. In addition, these sellers do not believe that the interest rate for commercial paper represents a proper compromise of all considerations, which should include customer costs. They support the Commission's proposal to tie the interest rate on refunds to the prime rate.

Several sellers pointed out that revenues received subject to refund are subject to Federal income taxes. As a result, the money actually available to a company because of overpayments is reduced by approximately 50 percent. It was argued that any rate on refunds imposed by the Commission should apply only to those funds actually available for use after taxes.

Finally, one jurisdictional utility argued that higher interest rates on refunds lead to higher rates of return and, as a result, have an inflationary impact upon the cost of energy for the ultimate consumer.

The comments submitted by jurisdictional customers (customers) generally focused on the losses, or costs to the consumer, resulting from excessive rates. Those losses are grouped into three types: (1) lost revenues because of increased borrowing; (2) lost income due to investments foregone; and (3) losses due to involuntary sacrifice of consumption. Additionally, customers indicated that, because the value of refunded monies continually declines and the price of postponed services and goods continually increases over time, there are also losses due to inflation.

Many customers stated that the interest rate on refunds should primarily reflect their average cost of borrowing money. According to customers, the prime rate is inadequate because if distributors or retail consumers are forced to replace rate overpayments with loans, few of them could borrow at rates as low as the prime. It is also of interest to note that customers alleged that many utilities are likewise unable to borrow at rates as low as the prime interest rate.

Another reason customers suggest a rate of interest on refunds higher than the prime rate concerns lost income due to foregone investments. Customers indicate that rate overpayments could have been invested in ventures (*e.g.*, common stock) which would earn more than the prime rate.

The prime rate is also alleged to be inadequate because it would not discourage jurisdictional utilities from filing excessive rates. Customers allege that utilities find it to their advantage to regularly file for excessive rate increases, commonly known as "pancaking," and thereby maintain a continuous source of inexpensive capital.

According to customers, overpayments due to excessive rate increases replace some of a utilities' requirements for short-term and medium-term (1–4 years) debt and, in some instances, may even allow a utility to postpone the sale of equity securities. Customers also note that there are no restrictions as to the use of these revenues, hence the excess funds may be directed towards other, highly-profitable, non-regulated businesses. In addition, customers note that these funds do not affect a utilities' debt/equity ratio as a conventional loan would.

For the above reasons, customers have suggested a wide range of standards, most of which vary from the prime rate to the prime rate plus four percentage points. Some customers proposed that the rate of interest be tied to the return on equity requested by the utility, or the overall rate of return allowed by the Commission in the filing which promulgated the overpayment. The rate most favored was the prime rate plus two percentage points.

B. Discussion. The comments submitted in this proceeding indicate, as anticipated, that no single money market indicator perfectly reflects the costs and benefits associated with excessive payments made by customers to sellers. There are even significant differences of opinion among customers as to the costs, and among sellers as to the benefits, of overpayments.

Sellers argue convincingly that their short-term borrowing rate is often less than the prime rate. We cannot be certain, however, that overpayments, which are indistinguishable from just and reasonable payments until a rate case is finally decided, do not have an effect on the timing and variety of all types of borrowings and investments by the sellers. Even assuming maximum suspension periods for filed rates, the complexity and magnitude of most rate cases leads to refund periods considerably longer than the terms of most commerical paper. In addition, to the extent that filings are pancaked, this lends an effect of permanency to the pool of refundable monies held by the sellers. Thus, while a portion of refundable monies replaces the need to issue commercial paper, by no means is it clear that any commerical paper rate fully reflects the benefits a company derives from the availability of excess funds.

Some sellers have indicated that, because a utility must pay income taxes on all revenues received, including those which are eventually refunded, it actually has the use of approximately only half of the money it eventually refunds. Hence, sellers suggest that the rate of interest on refunds should apply only to those revenues received on an after-tax basis.

Although the Commission recognizes the effect of income taxes, we do not believe that adjustment of the refund base to which interest is applied is warranted. First, while sellers' arguments have some merit as far as the sellers are concerned, these arguments have no application to the customers. Customers are required to pay the full amount of the overcharge, and their costs are in no way diminished by the effect of income taxes on the sellers. To require interest on only a portion of their overpayment would not be fair.

Furthermore, although income taxes do have the effect of somewhat reducing the benefits which a seller receives from excessive payments[1], our selection of a rate of interest on refunds represents a compromise of all the cost and benefit considerations. We believe it is of importance to note that it is the filing company which makes the determination as to what rates it will propose. A more conservative approach will expose it to less risk of refunds, therefore, less risk of loss due to the effects of income taxes, and vice versa. We believe that our selection of the prime rate properly reflects these income tax considerations, as well as all other pertinent concerns.

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[1] We note that even though a utility pays income taxes on revenues eventually determined to be excessive, it receives a tax deduction for the full amount of the refund (including accumulated interest) in the year in which the refund is made.

The responses submitted by the customers indicate that the costs associated with overpayments may vary according to the class of customer (*e.g.*, residential, industrial, other wholesale distributors, municipal, or co-operative). The variance is due to a number of factors, including lending rates available to the customer; the magnitude of any given rate increase upon a customer; the ability of a customer to pass on or take tax deductions for increases; and alternative uses to which the excess payments could have been put. Despite their unique characteristics, customers were unanimous in their opinion that the cost of overpayments to them is in excess of the prime rate.

The cost of borrowing short-term money is probably the greatest for the residential consumer, for whom credit is generally available only at 15–18% interest. While it is unlikely that a residential consumer will borrow money specifically to pay his/her gas or electric bill, utility costs nevertheless represent one of the ever enlarging expenses for the individual consumer today. As such, it could well be that rising utility rates represent a major factor in leading individuals to seek and use commercial credit.

Depending on the individual company, many commercial and industrial consumers are able to get lower commercial borrowing rates than residential consumers. However, even these rates are often not as favorable as the prime rate. Moreover, although commercial and industrial consumers can eventually deduct higher utility rates as expenses for tax purposes (they must also pay income taxes on any refunds ultimately received) the sheer magnitude of an increase may be enough to force some users to: (1) go to the commercial credit market for additional funds; (2) forego investments, at least temporarily, that could have earned in excess of the prime; and (3) forego consumption, thus reducing production and profits. Each of these eventualities may produce losses in excess of the prime rate. Moreover, competition may make it impractical or impossible for the industrial user to pass utility increases on to the ultimate consumer immediately, if at all.

Although the customers' comments generally focused on the residential consumer, the wholesale distributor may not, in all instances, pass rate increases (or refunds for that matter) on to the consumers. In those instances, the wholesale distributor will have to bear the burden of the increase for some time. Just as is the case with the consumers, some distributors do not have access to loans at the prime rate. Recognizing that the magnitude, and thus the impact, of a rate increase grows as an entity moves closer towards the seller in the distribution chain, there is also a greater probability that the wholesale distributor will have to seek commercial loans, or forego lucrative investments, to meet the increased cost.

Despite the differences existing between the classes of customers, two factors which affect all customers to some extent are: (1) the impact of inflation, and (2) the immediacy of a rate increase. First, the impact of double-digit inflation on those who bear the burden of excessive rates cannot be ignored. A rate of interest on refunds which does not take account of this trend in inflation cannot be said to be fully compensatory to the ratepayer, nor does it accurately reflect the benefits which have been received by the seller.

Second, we believe it is significant to note that it is not the customer who determines when and in what amount the rate increase will be filed; it is the seller. Thus, it may be assumed that the increase will commence at a time most advantageous to the financial needs of the seller, but may, in fact, come at a time when the customer is least able to withstand it.

The Commission has determined that the prime rate charged by commercial banks for short-term business loans achieves a proper balancing of the three primary considerations relevant to an appropriate interest rate on refunds (see discussion under II.A. *supra*.) As noted earlier, no one standard can perfectly reflect the costs and benefits associated with excessive payments. Our standard, however, comes as close as possible to a compromise solution that takes all of the above-mentioned considerations into account. Based on our analysis, we believe the prime rate generally may understate the costs to the ratepayer and overstate the benefits to the seller. While the situation will of course vary depending on individual sellers and customers, it is our belief that the prime rate will neither unduly prejudice nor advantage any party to a rate case. Moreover, to the extent that the prime rate understates the costs and overstates the benefits, the prime rate should provide a positive incentive for all parties to seek an early resolution of rate proceedings.

III. Compounding

A. Summary of Comments. Most of the sellers were opposed to the Commission's proposal to compound the rate of interest on outstanding refunds every month. It was alleged that compounding: (1) is not the standard banking practice on commercial loans; (2) is merely an add-on to the effective rate of interest thus simply increasing the refund burden; (3) attempts to add too much precision to a figure that is necessarily only an approximation; and (4) would be too complex. A minority of sellers, however, supported the concept of compounding.

All of the customers which submitted comments supported the Commission's compounding proposal. Some customers also suggested that because a utility uses overpayments daily and the consumer does without his money daily, the interest rate on refunds should be compounded daily.

B. Discussion. None of the sellers' arguments effectively refute the purpose of compounding, as expressed in the Notice of Proposed Rulemaking, *i.e.*, to reimburse the customer for the use of the accumulated interest on his overpayments. The sellers' comments raise only secondary issues which do not mitigate this overriding purpose. However, the four principal arguments of the sellers do warrant a response.

First, even if it is true that most commercial loans are stated on a simple, annual interest basis, their method of payment produces the same effect as if the interest were compounded during the year. This is because payments are typically required on a periodic basis (*e.g.*, monthly). As money is used to make these periodic payments, the borrower loses the potential earnings that this money could have earned elsewhere. The opportunity loss is the interest that these periodic payments could have earned during the year. Contrary to sellers' claims, the effect upon the borrower is therefore the same as if the borrower had paid a compound interest rate on his commercial loan.

Second, compounding is more than merely an addition to the specified rate of interest. It is a separate concept which addresses a goal distinct from determining the appropriate numerical rate of interest. Section II above, discusses the appropriate standard to be used as the numerical rate of interest to apply to refunds of the principal amount of overpayment. Here we are concerned with the reasonableness of allowing interest on accumulated interest. Compounding is the accepted method of providing for interest on interest. If compounding is correct in theory, as we have so determined, it should be adopted regardless of any implication it may have that the "effective" rate differs from a specified rate of interest.[3] However, the increased refund burden associated with compounding has, as we discuss below, had an effect on our determination as to the frequency with which we shall require interest to be compounded.

The third argument presented by the sellers is unconvincing. Merely because the interest standard we adopt cannot be precise in all respects, there is no reason not to strive for as accurate, fair, and comprehensive a refund methodology as possible.

The Commission has decided to adopt compounding on a quarterly basis, rather than the monthly basis which was proposed. Over a long period of time, the effects of compounding could become quite significant. It would, therefore, appear to be unduly burdensome to require monthly compounding of interest when the protraction of a case may, in certain instances, be due to no fault of any party. Moreover, in view of the number of different customers served and rate schedules maintained by some utilities, it appears that daily, or even monthly, compounding could increase their administrative burden and expense to a great extent. Quarterly compounding will also be consistent with the frequency of adjustment of the refund interest rate, as explained in detail in Section IV.

IV. The Automatic Adjustment Mechanism

A. Summary of Comments. With few exceptions, there was general agreement among all commenters that the interest rate on refunds should be allowed to fluctuate according to changing financial conditions. Some commenters, however, did object to that feature of the Commission's proposal which would require a rounding off of the interest rate on refunds to the nearest half of a percentage point. It was argued that rounding would only serve to reduce the accuracy of the rate. Alternate suggestions were rounding to the nearest one-quarter or one-tenth of a point, or no rounding at all.

Suggestions were also made to revise the Commission's proposal to adjust the interest rate every three months. One customer recommended adjustment every month, while one seller advocated change every six months.

B. Discussion. The rounding feature of our proposal will be eliminated. Just as we have required compounding in order to achieve a more realistic representation of the costs and benefits associated with overpayments, so should we utilize the actual (not rounded) prime rate in arriving at an average for the most recent three full months.

The Commission will, however, retain the adjustment mechanism on a quarterly basis. Except in a few isolated instances, we do not believe that the prime rate fluctuates enough from month to month to warrant a monthly adjustment in the interest rate on refunds.

In addition, monthly adjustments would appear to be unduly cumbersome to administer. On the other hand, we believe that recent history demonstrates that the prime rate can fluctuate frequently enough to warrant interest adjustments more often than twice a year.

We have incorporated minor changes to the proposed adjustment procedure in order to clarify the procedure and to delete the necessity for the Commission to regularly announce interest rates.

The automatic adjustment mechanism will operate in the following manner: the rate of interest on refunds to be applied during any given calendar quarter will be determined by calculating the arithmetic mean of the prime rates for the most recent three months for which values are available at the beginning of that quarter. Because the monthly *Federal Reserve Bulletin* in which the prime rate is published is not available until well into the next month, the most recent three months of known values will always be the second, third, and fourth months preceding each calendar quarter. Therefore, the interest rate on refunds during the first calendar quarter of any given year will be the arithmetic mean of the prime rates for the months of September, October, and November of the preceding year, as published in the December *Federal Reserve Bulletin*. Because the *Federal Reserve Bulletin* calculates the prime rate to the nearest one-hundredth percentage, we will require the same with respect to refund interest rate calculations.

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[3] The compound interest concept was not foreign to the Federal Power Commission. It required compound interest on refunds in individual cases in the past. *Trunkline Gas Co.* v. *Superior Oil Co.*, 35 FPC 335 (1966).

It is impossible to predict with precision what effect the new standard will have upon future refunds because (a) base refund amounts and refund periods cannot be predicted, and (b) the prime interest rate cannot be projected with any certainty. However, we can gain a meaningful insight into the likely effects of our new standard by viewing it in light of the recent past. (See Appendix A.)

The chart attached hereto showing fluctuations in the prime rate suggests that money market conditions have changed more often over recent years than has our rate of interest on refunds. As we noted in Section II, *supra*, the burdens and benefits associated with overpayments are closely related to money market conditions. When money is difficult and expensive to obtain, overpayments become more of a burden to the ratepayer and more of a benefit to the seller than when money is easy to obtain. We believe the prime rate is the money market indicator which best achieves an even balancing of these burdens and benefits. The new procedure will reflect current market conditions, and thus the current burdens and benefits associated with overpayments, more accurately and fairly than did the former method of computing interest.

We tested the practical consequences of our action by comparing the current interest rate procedure (using 9% simple interest) with the proposed procedure as if it had been in effect for hypothetical refund amounts over a recent timespan, thereby indicating generally the impact of our change in procedures. (See Appendix A.)

The results were consistent with our expectations. The closer the prime rate is to equalling or exceeding the present 9% rate, the more likely it is that refunds under our new method will exceed those payable under the current practice. Also, as can be seen from the tables in Appendix A, the length of time that revenues are held will now become significant due to the compounding feature. The larger the refund period, the greater will be the consequences of compounding. Upon review of the results reached in Appendix A, and in light of the interst rate goals hereinbefore stated, we do not believe the effects of our decision are unreasonable or will impose an undue burden upon any party.

V. Refund Requirements for Oil Pipelines

A. Summary of Comments. Comments received from the oil pipeline carriers allege that they are sufficiently dissimilar from natural gas pipelines and producers and electric utilities so as to warrant unique treatment, *i.e.*, a lower rate of interest on refunds. On May 23, 1979, the Association of Oil Pipelines (AOPL) filed a motion to initiate a separate interest rate on refunds rulemaking proceeding for oil pipelines, and sever it from this docket. The Commission has determined not to initiate a separate rulemaking proceeding with respect to oil pipelines. The motion of the AOPL is thus hereby denied. However, as discussed below, the Commission will give separate consideration to the arguments raised by AOPL.

The Oil Pipeline Board, the State of Alaska, and the Mid-Continent Petroleum Shippers unanimously support the Commission's oil pipeline refund proposals, with the exception of minor language changes to more accurately reflect the relationship between oil shippers and oil pipeline carriers.

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B. Discussion. The Commission is not persuaded that the circumstances surrounding the transportation of oil by pipeline warrant treatment different from that accorded natural gas pipelines, producers, and electric utilities.[3] However, because the regulation of oil pipelines is still a relatively new endeavor for this Commission, we have determined to postpone the issuance of any oil pipeline refund regulations pending oral argument on this issue.[4] The arguments should specifically address why the oil pipelines should or should not be subject to the same refund rates and procedures as are applicable to the other utilities under our jurisdiction. Specific changes in those refund rates and procedures, if any are recommended, should also be set forth. The Commission will announce refund regulations for the oil pipelines based upon the comments submitted thus far, and the oral argument, in a later order in this proceeding.

VI. Carrying Charges on Amounts Accumulated in the Deferred Purchased Gas Account

A. Summary of Comments. The majority of the comments received on this issue were in favor of the Commission's proposal to tie the carrying charge rate accrued on balances in Account 191 to that provided for interest on refunds, including quarterly compounding.[5] Other suggested rates for carrying charges were the overall rate of return allowed, and a rate "substantially below" that applied to refunds.

B. Discussion. The Commission will adopt its proposal to tie the carrying charge on balances in Account 191 with that rate provided for interest on refunds, including quarterly compounding. It is apparent that there are sufficient similarities between the origin of the base amounts, and the purpose of the interest, to warrant similar treatment with respect to interest rates. Deferred purchased gas costs represent temporary, unexpected expenses incurred by the supplier which are eventually repaid by the consumer. Tariff overcharges are expenses incurred by customers which are repaid by the sellers. Until they are repaid, the Commission provides for the accumulation of interest (or carrying charges) on the amounts outstanding. The interest rate (or carrying charges) represents the time-value of the funds during the period in which these expenses occur. Consistent with the goals set forth in Section II of this order, the interest (or carrying charges) portion of this payment is intended to place the parties, to the greatest extent possible, in the same position they would have been in had there been no delay in the recoupment of expenses.

Also of importance is the fact that a pipeline's Account 191 balance (including the total carrying charges allowed) is directly reduced by refunds from pipeline suppliers. In view of the direct relationship between refunds and the balance in Account 191, it is reasonable that both reflect an identical interest rate.

VII. AFUDC Rate

A. *Summary of Comments.* A few commenters suggested that, in addition to applying the interest rate on refunds to the amounts accrued in the deferred purchased gas account, the Commission should make the same rate applicable to calculations of the allowance for funds used during construction (AFUDC).

B. *Discussion.* The same underlying factors do not apply to AFUDC. The three costs a utility is permitted to recover while constructing a new plant are as follows: financing capital investment, interest, and return on equity. These combined costs are known as AFUDC. There are two methods by which these costs may be recovered from the ratepayers, *i.e.*, capitalizing AFUDC or including construction work in progress (CWIP) in rate base. To the extent that CWIP is not presently included in rate base, AFUDC costs for construction are added to the overall cost of the plant, which is then paid by the future ratepayers in the form of depreciation and rate of return on the augmented rate base.

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[3] For the most part, the arguments raised by AOPL for a separate proceeding are identical to those made in support of a lower interest rate for oil pipelines.

[4] The notice of oral argument will be issued separately from this order.

[5] Clarifying language has been added to section 154.38 of our regulations in order to make clear the requirement that interest on carrying charges is to be compounded in the same manner as interest on refunds.

As the Federal Power Commission (the predecessor agency of the Commission) noted in Order No. 561,[6] which established the formula for calculating AFUDC (*mimeo*, at 1):

> The stated objective of [the AFUDC formula] was to establish a method which would give recognition to the interrelationship between capital utilized for rate case purposes and the capital components of AFUDC in a manner that would permit a utility to achieve a rate of return on its total utility operations, including the construction program, at approximately the rate which would be allowed in a rate case.

Therefore it is apparent that the interest rate on refunds and the AFUDC rate are not meant to achieve similar goals. A major distinction is that the interest rate on refunds (and the carrying charge rate) is intended to strike a compromise between the costs and benefits associated with the underlying expense, while the AFUDC rate is aimed solely at the utility's cost of money. As such, we do not believe it is appropriate or necessary to require that they be identical. (Furthermore, the proposal to adopt the interest rate on refunds as the AFUDC rate is beyond the scope of the Notice of Proposed Rulemaking in this docket.)

VIII. Reduction in Number of Refund Reports

A. Summary of Comments. The majority of responses that were received on this issue were in favor of the Commission's proposal to reduce the refund reporting requirement from a monthly to an annual basis, subject to change in individual cases by the director of the appropriate office of the Commission. A few customers objected, however, on the basis that the monthly reports were necessary for rate case purposes, and because no standards are suggested for determining when more frequent reports might be required.

A few commenters suggested that sellers should be permitted in their annual refund reports to show the requested data only for the twelve months combined rather than for each month individually.

B. Discussion. The Commission has determined that no substantial revisions to its refund reporting proposal are warranted. To the extent that more information is required by a customer than is contained in the annual reports, that customer may always: (1) request the information through a data request; or (2) petition the director of the appropriate office for more frequent reports. Timely requests for extensions of time necessitated by these procedures will be considered in the usual manner. Because it would be impossible to predict all the reasons why an office director may require refunds reports more frequently than once a year, we will add to the proposed regulations that a request for more frequent reports will be granted if "good cause" is shown.

Despite the reduction in the number of reports, we will continue to require that the information be provided on a monthly, rather than on an annual, basis. Much, if not all, of the monthly information must be maintained by the seller for billing purposes. Moreover, this requirement should serve to minimize any inconvenience which customers may experience due to the reduction in the frequency of reporting.

IX. Miscellaneous

Some of the comments raised issues not addressed in the Notice of Proposed

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[6] Order Adopting Amendment to Uniform System of Accounts, Docket No. RM75-27, issued February 2, 1977.

Rulemaking. To the extent they are relevant to this proceeding, they are addressed here.

It was suggested that because not all billing periods end at the termination of a calendar quarter, the proposed interest rate should apply only to bills rendered during subsequent quarters. Our concern here is with refundable amounts held during a particular period, not with when the billing period may end. Keying the applicability of a particular interest rate to the billing period misplaces the focus of the interest requirement.

One commenter proposed that the ratepayers should be charged with the expense of maintaining records and making refunds. Contrary to the views of the commenter, the administration of such matters is not for the benefit of the customers. These procedures are merely for the purpose of assuring that the ratepayers remain whole despite having to pay excessive rates for a time. In fact, a necessary part of the statutory process by which utilities are permitted to increase rates is the maintenance of records and making refunds.

The Department of Energy filed comments requesting clarification of the applicability of this proceeding to Federal power rate cases. The Notice of Proposed Rulemaking did not address this issue nor have we considered whether the policies established in this proceeding are equally suitable for Federal power rate cases. We intend to propose at a future date procedures and policies to be followed in the event that a Federal power marketing agency's rate ultimately confirmed and approved by the Commission is lower than an interim rate being collected under the authority of the Assistant Secretary for Resource Applications.

Finally, we note that our regulations require gas pipelines and producers under our jurisdication to file (1) a motion to put a suspended rate into effect, and (2) an undertaking to comply with the refund and reporting procedures described in the refund regulations, before the suspended rate may become effective. We believe that the motion requirement adds nothing to the efficiency of the regulatory process, and should be eliminated. With respect to the undertaking requirement, the consistency with which gas pipelines and producers have made their required refunds over the years leads us to believe that undertakings are no longer necessary to assure that refunds will be made as prescribed by the Commission. Therefore, we are considering deleting the motion and undertaking requirements from sections 154.67 and 154.102 of the regulations. Written comments on this proposal should be submitted on or before October 9, 1979 to Kenneth F. Plumb, Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

The regulations which follow include amendments to sections 270 and 284 in order to conform with the amendment to section 273, which was proposed and is adopted as set forth below.

Pursuant to section 553(d) of the Administrative Procedure Act, 5 U.S.C. § 553(d), the Commission finds good cause exists to make this final rule effective on October 1, 1979, which affords less than 30 days notice subsequent to publication of the rule. Specifically, the regulations are designed to commence at the beginning of a calendar quarter; the next calendar quarter begins October 1, 1979. A primary purpose of this rule is to track the average prime rate for refund purposes in order to reduce the financial burdens upon customers due to rate overpayments. The Commission finds that the rate at which the prime interest rate is rising requires that the rules be made effective for the upcoming calendar quarter in the order that customers may be adequately compensated with respect to refunds ultimately determined to be payable.

(Section 16, Natural Gas Act, 15 U.S.C. 717o; section 309, Federal Power Act, 16 U.S.C. 825h; section 15(7) of the Interstate Commerce Act, 49 U.S.C. 825h; section 15(7) of the Interstate Commerce Act, 49 U.S.C. § 15(7); Department of Energy Organization Act, Pub. L. 95–91; E.O. 12009, 42 F.R. 46267.)

In consideration of the foregoing, Parts 35, 154, 270, 273 and 284 of Chapter

1. Title 18, of the Code of Federal Regulations are amended as set forth below, effective October 1, 1979.

By the Commission.

Kenneth F. Plumb,

Secretary.

Appendix A

Some Observations About the Comparative Magnitudes of Refunds Under the Existing and New Refunds Interest Rate (RIR) Procedures

We have noted that it is not possible to demonstrate with any precision what the "effect" of the RIR procedure we are here implementing will be. This is simply because, although it is certainly true that refund amounts cannot be predicted, it is perhaps even more important to realize that future values of the prime interest rate cannot be forecast with absolute certainty.

In lieu of such infeasible analysis, we have developed some hypothetical refund scenarios to illustrate the new RIR procedure. In so doing, we compare refund interest amounts on hypothetical refunds over selected historical timespans for (a) the existing (constant 9% simple interest) RIR procedure and (b) the new RIR process (as if it has been in effect) and can thereby gain some rough idea about what impact the new procedure can have in relation to our current practice. We must qualify the results given here by stating at the outset that they are sensitive to both the refund principal amounts and the timespans (lengths *and* dates) used. Nonetheless, there are some general tendency conclusions that can be drawn, and we shall note these.

Table I gives raw monthly data on interest rates for the period Sept. 1976–April 1979. The values labeled "New RIR For Quarter" are seen to be the simple three-month averages of actual prime rate values which constitute the relevant derivation for the new RIR procedure. It will be recalled that the value for any quarter is applied to each of the three months that comprise that quarter. The last column displays the constant 9% interest rate currently used on a simple interest basis in RIR determinations.

Table II presents two hypothetical refund situations:

Case A—Refund of $100,000 excess revenue collected in each of Quarters 77–2, 3, 4, is ordered halfway through the second quarter of this year (1979).

Case B—Refund of $100,000 excess revenue collected in each of Quarters 78–4 and 79–1 is ordered, again halfway through Q79–2.

The new and current method RIR values are simply taken from Table I. Column 4 gives the total new method refund (principal + quarterly compound interest) in each of Cases A and B. To aid interpretation, the $116,390 figure for Quarter 77–3, for example, is the total new method amount to be paid with respect to the $100,000 excess revenue collected during Q77–3, where quarterly compounding has been applied for the 7½ quarters the money was held. In contrast, the $116,875 amount in Column 7 shows the amount to be paid under the current RIR method where simple interest has been calculated, again for 7½ quarters.

It is seen that in Case A, all quarters would have had lower refunds under the new RIR procedure than under the existing constant simple interest rate. In Case B, however, the new procedure refunds for both quarters would have exceeded the current method amounts.

It is thus apparent that neither method will lead to higher (lower) refunds in all instances; specific situations must be examined individually. As tentative observations, however, we can observe that:

(1) The closer the prime rate values over a timespan in question are to equalling or exceeding the 9% constant rate, the more likely it is that refunds under our new method will exceed those payable under the current practice. Case B shows this clearly, and Case A's Q77–4 new and current method values (which are almost equal) suggest it when one realizes that the prime rate values applicable to the Q77–4 timespan are, as a group, higher than the values for the preceding two quarters.

(2) The length of time that excess revenues are held can make a difference (as one would intuit), since the longer compounding cumulates, the greater will be the value under the new procedure. One can see, for example, that the difference between current and new method amounts is greater for Q77–2 ($907) than for Q77–3 ($485), where this result is primarily attributable to the additional quarter of time over which Q77–2's amount was held since the prime rates are virtually the same for both quarters.

Table 1

Refunds Interest Rate (RIR) Values
(Interest Rates Are Annual Percentages)

Year - Mo.		Prime Rate*	Quarter	New RIR for Quarter**	Current RIR for Quarter
1976	Sept.	7.00	--	--	--
	Oct.	6.78	76-4		
	Nov.	6.50			
	Dec.	6.35			
1977	Jan.	6.25	77-1	6.76	9.00
	Feb.	6.25			
	Mar.	6.25			
	Apr.	6.25	77-2	6.28	9.00
	May	6.41			
	June	6.75			
	July	6.75	77-3	6.30	9.00
	Aug.	6.83			
	Sept.	7.13			
	Oct.	7.52	77-4	6.78	9.00
	Nov.	7.75			
	Dec.	7.75			
1978	Jan.	7.93	78-1	7.47	9.00
	Feb.	8.00			
	Mar.	8.00			
	Apr.	8.00	78-2	7.89	9.00
	May	8.27			
	June	8.63			
	July	9.00	78-3	8.09	9.00
	Aug.	9.01			
	Sept.	9.41			
	Oct.	9.94	78-4	8.88	9.00
	Nov.	10.94			
	Dec.	11.55			
1979	Jan	11.75	79-1	10.10	9.00
	Feb.	11.75			
	Mar.	11.75			
	Apr.	11.75	79-2	11.68	9.00

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* .From various issues of the Federal Reserve Bulletin.

** Calculated as the arithmetic mean of the most recent 3 months' prime rate values that are available on the last day of a calendar quarter and are published in the F.R. Bulletin. For the quarter 77-2, for example, the relevant observations are: Dec. 1976; Jan. and Feb. 1977. This is because the March 1977 prime rate was not published in the F.R. Bulletin until well into April.

Table II

Illustrative Hypothetical Refund Calculations For Current and New Refund Interest Rates (RIR's): As If The Latter Had Been in Effect

Quarter (1)	Refund Amount (2)	New RIR (%) (3)	Refunds + Interest, Compounded Quarterly 1/ (4)	Current Method RIR (%) (5)	Refunds + Interest, Currently 2/ (6)
77-1		6.76		9.0	
-2*	$100,000	6.28	$118,218	9.0	$119,125
-3*	100,000	6.30	116,390	9.0	116,875
-4*	100,000	6.78	114,586	9.0	114,625
78-1		7.47		9.0	
-2		7.89		9.0	
-3		8.09		9.0	
-4#	100,000	8.88	106,320	9.0	105,625
79-1#	100,000	10.10	104,011	9.0	103,375
-2@		11.68			

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*,# The locked-in periods during which excess revenues were collected -- Case A(*) and Case B (#)

@ Assume refund orders are issued halfway through 79-2 quarter.

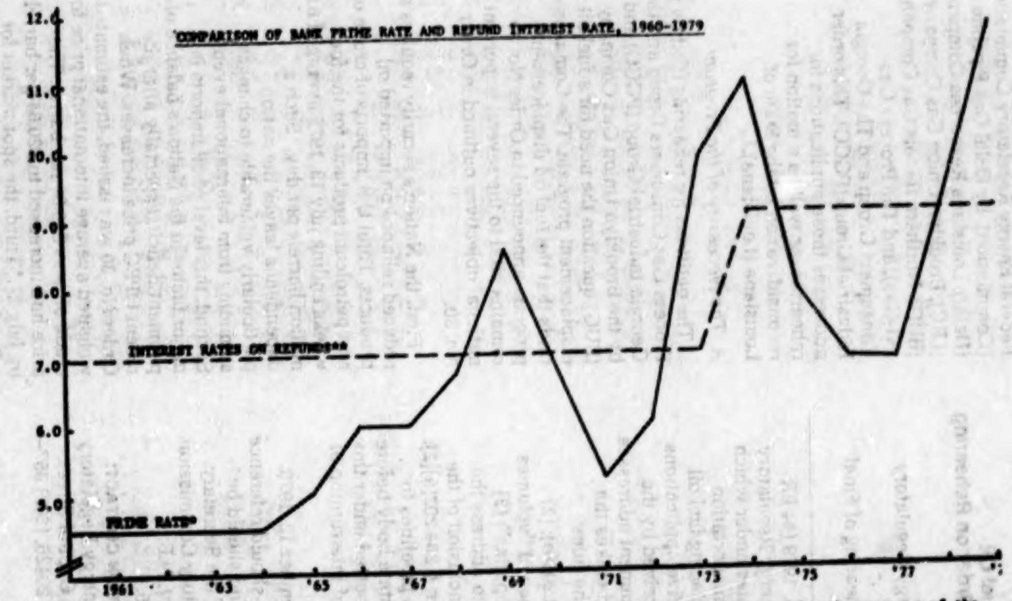
1/ Compound amounts are calculated by using for each quarter in which interest is owed the RIR specific to that period. The annual basis RIR values must be converted to the corresponding sub-annual rates and then be compounded for the correct number of periods. For example, the 77-4 quarter refund amount is calculated over 6½ quarters as:

$$A^{Q}_{77-4} = (100{,}000)(1 + 0.0678/4)(1 + 0.0747/4) \ldots (1 + 0.101/4)\ (1 + 0.1168/4)^{0.5}$$

2/ Simple interest amounts are calculated by forming a multiplier factor based on the number of years a refund amount was held. For example, Quarter 77-2's amount was held for 8½ quarters, or 2.125 years. The refund plus interest is thus:

$$A_{77-2} = (100{,}000)\ \underline{/}1 + (2.125)\ (0.09)\underline{7}$$

COMPARISON OF BANK PRIME RATE AND REFUND INTEREST RATE, 1960-1979



* Rates shown reflect end-of-year levels for 1960-1973; rates shown for 1974-1978 reflect arithmetic averages of the twelve monthly weighted averages; rate shown for 1979 reflects arithmetic average of the monthly weighted averages through June.

** Rates reflect appropriate rates in effect at end of year.

Note: Order 215A (March 3, 1960) raised rate for independent natural gas producers to 7.0 percent, rates for pipelines and electric utilities set on a case by case basis; Order 442 (December 3, 1971) extended 7.0 percen coverage to pipelines and electric utilities; Order 513 (October 10, 1974) raised all refund rates to 9.0 percent.

[¶ 30,084]

44 F. R. 54472 (September 20, 1979)

18 CFR Part 284

[Docket No. RM79-34; Order No. 30-A]

Transportation of Fuel Oil Displacement Gas; Order on Rehearing of Final Rule

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Order on Rehearing of Final Rule.

SUMMARY: On May 25, 1979 (44 FR 30323), the Federal Energy Regulatory Commission issued rules under which certain natural gas transportation arrangements for displacing fuel oil could be authorized. Five applications for rehearing were received by the Commission. This document addresses those applications and makes the following changes in the rules:

(1) Deletion of § 284.200(b); (2) revision of the definition of "volumes attributable to local supplies"; (3) inclusion of a section to address the "Hinshaw" issue; (4) inclusion of the words "on behalf of" in § 284.202(a)(2); (5) requiring intrastate pipelines to report to appropriate state body before selling gas to be transported under this subpart; (6) inclusion of interruption of service provision.

EFFECTIVE DATE: September 12, 1979.

ADDRESSES: All filings should reference Docket No. RM79-34 and should be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Philip Yates, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8078.

September 12, 1979.

On May 17, 1979, Order No. 30 [1] was issued in Docket No. RM79-34. Order No. 30 set forth the rules under which certain natural gas transportation arrangements for displacing fuel oil could be authorized.

I. Applications for Rehearing

Five applications for rehearing of Order No. 30 were submitted to the Federal Energy Regulatory Commission (Commission), by Delhi Gas Pipeline (Delhi), Louisiana Resources Company (LRC), Brooklyn Union Gas Company (BUG), Northern Illinois Gas Company (NI-Gas), and The Process Gas Consumers Group and The Georgia Industrial Group (PGCG). This order addresses those applications for rehearing, as well as a motion for reconsideration by the State of Louisiana (Louisiana).[2]

A. The Necessity of the Program

The petitions for rehearing filed by the Process Gas Consumers Group and the Georgia Industrial Group (PGCG) and by the Brooklyn Union Gas Company (BUG) question the need for a fuel oil displacement program. The Commission finds that the fuel oil displacement program announced in Order No. 30 remains vital to the several important national objectives outlined in Order No. 30.

First, the Nation's security requires a reduced reliance on imported oil products. Total U.S. imports of crude oil and petroleum products for the four weeks ending July 13, 1975 averaged 8.0 million barrels per day.[3] Such a dependence leaves the nation particularly vulnerable to changes stemming from international events. Second, this level of oil imports is a major factor in the Nation's balance of payment deficit, especially after the recent OPEC price increases. When Order No. 30 was issued, the estimated weighted average international price for crude oil was $16.67 per barrel. The price had increased to $20.64 per barrel by July 27.[4] Third, the spot market for refined oil products has grown increasingly tight.[5] However, since Order No. 30 was issued, the Nation's supplies of critical middle distillates has increased to 157 million barrels, which is slightly above the minimum acceptable level for this time of year but still 12 percent lower than a year ago.[6] We take official notice of the July 27, 1979 DOE Report, which demonstrates that the objectives of Order No. 30 continue to warrant a high national priority. We also take official notice of the July 10, 1979, Presidential Proclamation of a National Energy Supply Shortage, in which the President declared: "A severe supply interruption * * * currently exists with respect to the supply of imported crude oil and petroleum products." This Proclamation was based on the Secretary of Energy's finding that "current and projected imports of crude oil and petroleum products, plus available stocks, are not adequate to meet normal demand and the shortages of essential fuels have begun to have a major adverse impact on the economy with the possibility of more severe impacts occurring in the future."

B. Delhi Gas Pipeline

Delhi suggests that the Commission amend § 284.202(b)(1) to allow for section 311(a) transportation authorization for volumes sold by intrastate pipleines at prices higher than the price allowed under section 311(b) of the Natural Gas Policy Act of 1978 (NGPA); *i.e.*, the intrastate pipelines' "weighted average acquisition cost" of natural gas. Further, Delhi would have the Commission delete the last sentence of § 284.208(a), which does not provide for Natural Gas Act section 7(c) certificates to authorize "covered transportation" of natural gas sold by an intrastate pipeline to an eligible user.[7]

Delhi bases theses suggested revisions on policy grounds. Delhi states that it has large quantities of natural gas to sell to eligible users to displace fuel oil, but it will not sell the gas at the NGPA section 311(b) price because that price is less than Delhi's replacement cost. Delhi states that a different price limit, the NGPA section 102 new gas price plus State severance taxes, would cover the replacement cost of Delhi's gas.

While Delhi's position regarding replacement costs may limit the amount of gas moving under Order No. 30,[8] the price limitation will not be changed. As stated in Order No. 30, at page 10, the price limitation was imposed to place eligible users in a bargaining position similar to that of interstate pipelines and local distribution companies served by interstate pipelines, who are subject to a price limitation system imposed by section 311(b) of the NGPA. While the Commission does wish to maximize the amount of fuel oil which can be displaced through the use of natural gas, we do not feel that Order No. 30 should operate to the disadvantage of the high priority users served by interstate pipeline and local distribution company system supply.

C. Brooklyn Union Gas Co.

BUG claims that Order No. 30 is predicated upon two erroneous assumptions: (1) That there is a surplus of natural gas and (2) that there is a shortage of residual fuel oil. The Commission believes that the first assumption is not in error, and that BUG's characterization of Order No. 30's reliance upon a shortage of residual fuel oil reflects a misunderstanding of the purpose of Order No. 30.

First, there does appear to be excess deliverability of natural gas which may be utilized to displace fuel oil. According to Department of Energy estimates, even if all essential agricultural users are given 100 percent of their needs, 341 additional Bcf of natural gas deliverability remain.[9] Second, Order No. 30 was prompted not by a shortage of residual fuel oil, but by a shortage of middle distillate fuel oil.[10] The distillate shortage has been documented in the record established in Docket No. RM79-34.[11]

However, BUG's suggestion that Order No. 30 authorization be conditioned only upon middle distillate displacement must be rejected. While the objective of Order No. 30 centers upon displacing middle distillate fuel oil, this Commission is unable to determine that this objective would be best advanced by limiting authorization solely to transactions involving the direct displacement of middle distillate fuel oil with natural gas. The refining and distribution of petroleum products is a vast and complex area of which the Commission has imperfect knowledge. Nonetheless, it is clear to us that transactions involving the displacement of residual fuel oil could in some instances have the same ultimate beneficial impact on middle distillate consumers as would a transaction involving the direct displacement of middle distillates. For example, displacing residual oil with natural gas will increase the availability of residual fuel oil to other users. If such other users have the capability to burn either residual fuel oil or middle distillates, the increased supply and/or lower price of residual fuel oil for these users might result in the displacement of middle distillate fuel oil with residual fuel oil.

In addition, residual oil can often be further refined to produce additional distillate fuel oil. Some refiners may find it profitable to reduce yields of residual fuel oil and maximize yields of middle distillate fuel oil, if Order No. 30 reduces demand for residual fuel oil.

These illustrations suggest that there is not a sharp division between residual fuel oil and middle distillate oil, either as to how such products are refined or as to how they are ultimately consumed. Transactions involving the displacement of residual fuel oil may, ultimately, have the same beneficial impact on distillate supplies as transactions involving the direct displacement of middle distillate fuel oil.

Further, the objective of Order No. 30 is not only to displace middle distillate fuel oil, but also to reduce our dependence on imported oil. This dependence has necessitated the President's declaration of the previously mentioned national energy supply shortage. Because roughly one million barrels per day of residual fuel oil are imported, the Order No. 30 program will directly reduce petroleum imports.

Accordingly, the Commission concludes that any decision to narrow the scope of Order No. 30 to permit only direct displacement of middle distillates could inhibit rather than enhance the purposes of the program.[12]

However, Order No. 30 provides the opportunity for interested parties to show that a transaction authorized under Subpart F of Part 284 will not advance these objectives. The Commission would consider whether a transaction conforms to the purpose of Order No. 30 in either the certification proceeding under § 284.208, or a termination proceeding under § 284.205(d)(2). In either proceeding, the presumption accorded the Economic Regulatory Administration (ERA) certificate holder (that premium fuels or imported products are displaced) may be rebutted.

BUG also objects to the interruptibility provisions contained in Order No. 30. The Commission agrees with BUG's position that natural gas transported under Order No. 30 should be interrupted before *any other* natural gas transported by the pipeline. *See* § 284.205(f).

BUG also seeks the elimination of the § 284.206 curtailment assurance provision. The Commission does not find any of the three arguments advanced by BUG as grounds for deleting § 284.206.

First, BUG considers § 284.206 to be unnecessary for pipelines which employ a fixed base period curtailment plan. While § 284.206 would have no immediate effect upon such plans, customers of pipelines with fixed base period plans have sought the Commission's assurance that should the fixed base period ever be updated, fuel oil displacement transactions occurring during the brief fuel supply emergency period will not be reflected in the revised data.[13] BUG's assertion that § 284.206 is unnecessary is therefore contradicted by other comments in this docket.

Second, BUG alleges that § 284.206 would provide a "premature and wholly piecemeal" determination regarding the treatment of fuel oil displacement volumes in future curtailment plans. While the Commission agrees with BUG that the exact effect of § 284.206 upon individual pipeline curtailment plans must be determined in individual curtailment proceedings, the Commission cannot permit uncertainty to thwart an emergency program to improve the nation's serious fuel supply situation. The Commission takes official notice of the fact that both the buyers and sellers in all three fuel oil displacement hearings conducted to date have conditioned their contracts upon receipt of adequate curtailment assurances.[14] The ERA proposed a curtailment provision to assure participants in a fuel oil displacement transaction that they would not "be penalized in any future curtailment proceeding as a result of such participation." [15] Because the purpose of § 284.206 is to provide necessary present assurances against future adverse consequences, the Commission cannot view § 284.206 as "premature."

Finally, BUG claims that § 284.206 can be misused "to upgrade or artificially restate its actual market requirements and related supply sources." [16] BUG's fears are unfounded. Because the fuel oil displacement volumes will not be reflected in the market profiles of any customers, such volumes cannot be used to inflate any future base period data over pipeline supplier contract demand.

Similarly, in the case of a local distribution company which sells volumes attributable to local supplies, since the fuel oil displacement volumes will be excluded from both his own market profile as well as that of the local distribution company's interstate pipeline suppliers, § 284.206 could not "be used as a sword rather than a shield" as is claimed by BUG. Should some unanticipated combination of events arise in a future curtailment proceeding wherein § 284.206 created an unfair advantage or undue discrimination, BUG or any other potentially aggrieved party remains free to raise the issue in the future proceeding.

Because of the need to provide present assurance to participants in fuel oil displacement transactions, the Commission will not eliminate the provision based upon speculation as to possible unintended results.

D. Northern Illinois Gas Company

NI-Gas has made suggested revisions to the rule which fall into two general categories: (1) Interruptibility and (2) the desirability of using system supply gas whenever possible. NI-Gas's interruptibility suggestion has been adopted in the final rule, in § 284.205(f). The other suggestion is rejected for the reasons set forth below.

NI-Gas claims that the *only* way to assure that a first priority will be given to fuel oil displacement by interstate system supplies is to give local distribution companies a veto over "covered transportation" to eligible users located in the local distribution company's service area. We disagree. NI-Gas's proposal would entrust the Commission's statutory duties to a private company. Instead, the Commission will examine each proposed transaction involving natural gas otherwise available to the interstate market. The Commission will conduct a full inquiry into each transaction to determine whether the transaction is required by the present or future public convenience and necessity.[17] Thus, the extent to which transaction will divert natural gas from the interstate system supplies of another pipeline to the eligible user will be examined in the proceeding conducted under § 284.208.

E. Louisiana Resources Co.

LRC objects to § 284.200(b), which states that Subpart F of Part 284 is the only provision of Part 284 which authorizes section 311(a) transactions involving gas "owned by an end-user or which after such transportation will be sold directly to an end-user." LRC indicates that this provision will eliminate intrastate participation in transportation transactions authorized by Section 7(c)(2) of the Natural Gas Act involving natural gas owned by end-users, as well as intrastate pipeline utilization of interstate pipelines to transport such gas. Section 284.200(b) has been removed to eliminate this concern. Final rules in Part 284 involving section 311(a) transportation have rendered § 294.200(b) superfluous.

Under the final rules implementing section 311(a), transactions involving end-user owned gas, or gas delivered directly to an end-user can still go forward, but only with prior Commission approval. The Commission feels that, except for carefully prescribed emergency programs such as Order No. 30, such transactions should be scrutinized.[18] This requirement is consistent with the rules governing the transportation of gas reserves purchased in-place by an eligible user who is also an essential agricultural user; such a transaction would be subject to the certification requirements of the Natural Gas Act under either Order No. 27 or Order No. 30. The Commission considers consistency in the case by case review of such transactions to be necessary to protect the public interest.

F. The Process Gas Consumers Group and the Georgia Industrial Group

PGCG offers the prepared direct testimony of Dr. Thomas R. Stauffer as part of its application for rehearing. Because Dr. Stauffer's testimony was made after the close of the comment period, our consideration of the testimony would be unfair to other parties which are deprived of an opportunity to respond to it. As a result, Dr. Stauffer's untimely testimony will not be considered with the record in Docket RM79-34. However, if the Commission were to consider Dr. Stauffer's testimony, fairness would dictate that the Commission also consider the cross-examination of Dr. Stauffer and the rebuttal testimony offered in Docket Nos. CP79-214 and CP79-228.

PGCG raises several other issues involving Order No. 30 which must be addressed. First, PGCG alleges that Order No. 30 is defective in that the Commission has failed to determine and consider the impact of the order upon consumers. The Commission has considered the impact of the order on consumers and finds that high-priority users will not be adversely affected by the order.

The natural gas transported under Order No. 30's self-executing provisions is natural gas that is not part of interstate pipeline system supply but is surplus natural gas supplies of intrastate pipelines and the excess local supplies of local distribution companies. Those transactions that do involve interstate system supply gas will be carefully examined before authorization is granted. In that examination process, the impact upon the customers of "natural gas companies" will be scrutinized. Obviously, the Commission cannot at this time precisely gauge the extent of the impact of Order No. 30, because we do not, and cannot, know the extent to which it will be used. However, we feel that the information available to us at this time supports our conclusion that the transactions authorized by Order No. 30 will be in the public interest.

PGCG indicates that this lack of knowledge, which includes not knowing precisely how much fuel oil must be displaced to meet the goal of 240 million barrels of middle distillate fuel oil, means that there is no justification for the one-year period.

We disagree. Precisely because we do not know, at this time, how well Order No. 30 will function in displacing middle distillate fuel oil, we feel that a one year program is necessary to encourage participation. If, as a result of our ongoing review of that Order No. 30 program, we determine that the emergency that engendered Order No. 30 no longer exists, we can refuse to allow additional transactions under the program.

Second, PGCG alleges that the information in the record in Docket No. RM79-34 indicates that middle distillate fuel oil production will be diminished rather than increased by the Order No. 30 program. This allegation is based in part on the comments received from crude oil refiners indicating that they may be induced to cut back their production of all refined products, including middle distillate fuel oil, due to an inability to market the residual fuel oil produced. In view of the fact that the U.S. imports over one million barrels of residual fuel oil a day, the Commission cannot agree that displaced residual fuel oil will result in a nationwide surplus that will cause refineries to cut back production of middle distillate fuel oil. However, regional surpluses may occur that will have that effect. The ERA may wish to consider such regional surpluses in determining the appropriateness of granting certificates of eligible use. If, in our continuing review of the Order No. 30 program, we find that refineries are cutting back middle distillate production due to a surplus of residual fuel oil created by the program, the Commission will act rapidly.

Finally, PGCG claims that Order No. 30 is defective on four separate procedural grounds: Lack of notice, exemption from certificate requirements, inconsistency in filing requirements, and the type of data the Commission requires.

The notice objections involve two points: Failure to provide adequate rulemaking notice and failure to provide adequate notice of specific transactions. PGCG contends that the Commission failed to provide adequate notice of the possibility that the final rule would rely upon section 311(a) of the NGPA to authorize fuel oil displacement transmission on a self-implementing basis. However, the Notice of Proposed Rulemaking upon which comment was sought [19] contemplated the use of section 311(a) of the NGPA to authorize fuel oil displacement transportation by observing that "direct purchase gas" in a targeted fuel oil displacement program could be transported under section 311(a). Thus, the preamble to the Notice of Proposed Rulemaking placed PGCG on notice that self-implementing fuel oil displacement transactions under Section 311(a)(1) were contemplated.

As for specific transactions, there is a period of notice provided in the ERA's certification procedure.[20] Since ERA certification is a prerequisite to Order No. 30 transportation authorization, interested parties can identify possible eligible users prior to the transportation of natural gas, and file protests with ERA. However, the Commission will publish a notice of self-executing transactions on a bi-weekly basis.

The exemption from the requirements of section 7 of the Natural Gas Act stems from the Commission's determination, based on data from the Department of Energy, that the nation is in an emergency situation due to a critical shortage of middle distillate fuel oil and the recent pressure on fuel oil imports. As noted above, the President has declared a national energy supply shortage for this very reason. The exemption applies only to first sales of natural gas which is not "committed or dedicated." The Commission feels that the public interest is well served by the rapid implementation of the Order No. 30 program. By dispensing with unnecessary certification procedures, that rapid implementation may be accomplished.

PGCG questions why a local distribution company, under § 284.202(b)(2), must file notice with its state commission before making a sale of natural gas which will be transported under the program, while an intrastate pipeline does not. Upon reconsideration of this distinction, the Commission finds that it is undesirable. Consequently, intrastate pipelines as well as local distribution companies will be required to notify their state commission before selling such natural gas. The requirement is imposed to assure that state authorities are kept informed, in advance, of the natural gas that is leaving their jurisdiction under Order No. 30.

Finally, the data that is alleged to be "critical" by PGCG is not needed by the Commission as a separate application requirement. Data on the types of fuel oil to be displaced is presently submitted to ERA; § 284.208(b)(9) is amended to require that the data submitted to ERA be included in the application submitted to the Commission. Also, most selling interstate pipelines have already supplied the Commission with supply and curtailment data in FERC Form 16. *See* 18 CFR 260.12. Further, there is no need for intrastate pipelines and local distribution companies to submit curtailment data, since they are not subject to the Commission's curtailment authority.

II. Louisiana's Motion for Reconsideration

On July 13, 1979, the State of Louisiana (Louisiana) filed in this Docket a "Motion for Reconsideration or, in the Alternative, Petition for the Deletion of § 284.200(b) from the Commission's Rules." Although Louisiana's motion is not an application for rehearing of Order No. 30, the Commission is considering the motion in this order due to its close relationship with the issues raised on rehearing.

First, Louisiana seeks to have § 284.200(b) deleted as its provisions would be better expressed as an amendment to other subparts of Part 284. We agree, and have deleted the section in the final rules in Part 284. Second, Louisiana contends that § 284.200(b) constituted an impermissible rulemaking because of its retroactive effect. Louisiana is incorrect, as the provisions of § 284.200(b) became effective on May 17, 1979, the day that Order No. 30 was issued. The Commission has not applied § 284.200(b) to transactions completed before that date.

III. Section by Section Analysis of Amendments to the Rule

Section 284.200

Paragraph (b) is deleted in light of amendments to Part 284.

Section 284.201

The definition of "volumes attributable to local supplies" is revised to make clear that the molecular flow of natural gas sold by a local distribution company in self-implementing transactions need not be traced to sources other than interstate system supplies.

Paragraphs (h), (i) and (j) are added to indicate that so-called "Hinshaw pipelines" are to be treated as local distribution companies for the purpose of this subpart.[21] This will clarify any ambiguity that may exist pending the outcome of the rulemaking proceeding in RM79-24.

Section 284.202

Paragraph (a)(2) is amended to make clear that covered transportation must be "on behalf of" a local distribution company or intrastate pipeline. This requires a nexus between the selling intrastate pipeline or local distribution company and the transporting interstate pipeline. Paragraph (a)(2) is modified to include section 311(a) of the NGPA or section 7(c)(1)(B) of the Natural Gas Act as the statutory basis for exempting covered transaction from the certification requirements of section 7(c) of the Natural Gas Act.

Paragraph (b)(2) is amended to include intrastate pipelines in the section, thus requiring an intrastate pipeline to report to its appropriate state regulatory agency before selling gas which will be transported under Subpart F.

Section 284.205

Paragraph (f) is added to create a heirarchy of interruption to be applied by an interstate pipeline when required to interrupt transportation as a result of pipeline capacity problems.

The lowest priority, in § 284.205(f)(2)(i), includes both transportation authorized under § 284.206 as well as under certificates resulting from applications which predate Order No. 30. The next priority represents natural gas obtained from sources other than interstate system supplies. Creation of a special capacity curtailment priority for such supplies reflects our stated general policy which favors increasing the total volume of natural gas available to interstate system supplies. Paragraph (f)(2)(iii) subordinates both categories to all other transportation services, including those rendered under Order No. 27, Order Nos. 533 and 2, and section 311(a) of the NGPA, regardless of the end-use of the natural gas.

Section 284.208

Paragraph (a) is amended to permit Hinshaw pipelines which seek to sell volumes in excess of those attributable to local supplies to apply for a certificate of public convenience and necessity under the procedure established by this section.

Paragraph (b) contains additional changes in the application requirements. Both the eligible user's application for an ERA certificate of eligible use as well as the final certificate must be submitted. This will permit the ERA to incorporate by reference application data into the final certificate. Because sales by interstate pipelines raise special issues within the Commission's ratemaking jurisdiction, subparagraph (b)(12) requires interstate pipeline sellers to provide a statement justifying the sales price of the gas. The Commission will review this statement to insure that the other customers of the interstate pipeline are not subsidizing the sale to the eligible user.

Paragraph (d) is amended to clarify the authority of the Presiding Administrative Law Judge to prescribe additional issues for hearing. Subparagraph (d)(4) is added to reflect the Commission's concern that direct sale fuel oil displacement transactions do not interfere with our stated first priority of achieving fuel oil displacement through regular sales of interstate system supplies.

A new paragraph (e) explicitly states that this rule is not intended to shift away from the applicant the burden of establishing that the public convenience and necessity is served by granting the application. However, the Commission will accord great weight to the ERA certificate of eligible use on the question of whether the eligible user will be furthering the public interest objectives of this program when receiving natural gas pursuant to this subpart. The presumption created by paragraph (e) is subject to rebuttal by evidence adduced by any party at the hearing.

The Commission orders: The applications for rehearing are denied.

18 CFR Part 284 is amended as set forth below.

(Natural Gas Act, 15 U.S.C. 717 *et seq.*, Natural Gas Policy Act of 1938, Pub. L. 95-621, Department of Energy Organization Act, Pub. L. 95-91, E.O. 12009, 42 FR 46267).

In consideration of the foregoing, Part 284 of Subchapter I, Chapter I, Title 18, Code of Federal Regulations, is amended as set forth below. Because the amendments promulgated herein implement an emergency program, the Commission finds that further notice and public procedure are impracticable, unnecessary, and contrary to the public interest. Consequently, these amendments are effective upon the issuance of this order on rehearing.

By the Commission. Commissioner Holden will have a separate statement to be issued later.

Kenneth F. Plumb,
Secretary.

—Footnotes—

[1] 44 FR 30323 (May 25, 1979).

[2] The comments that were received, and analyzed by the Commission in formulating the fuel oil displacement program raised several issues that were considered but not fully addressed in Order No. 30. These were: (1) That the program should be limited to those cases where a traditional supplier has insufficient system supplies to satisfy the needs of the eligible user, (2) objections to curtailment immunity, and (3) possible reductions in refinery output of middle distillate fuel oil, due to a developing surplus of residual fuel oil. These issues are again raised in the applications for rehearing, and will be fully addressed in this order.

[3] U.S. Department of Energy Weekly Petroleum Status Report, Pub. No. DOE/EPC-0017, July 27, 1979.

[4] On May 16, 1979 The Rotterdam spot market price for middle distillate was $43.90 per barrel, it rose to $48.26 on July 20. The Rotterdam price for 1 percent sulphur residual oil increased from $22.75 per barrel to $25.15. *Id.*

[5] *Id.*

[6] *Id.* Middle distillate stocks must reach 240 million barrels to meet the demands of next winter's heating season. Tr. 19.

[7] "Covered transportation is defined in § 284.201(b) to mean "transportation during the fuel shortage emergency period of natural gas by an intrastate pipeline for ultimate delivery to an eligible user."

[8] Cf Tr. 181 (Statement by Counsel to Lo Vaca Gathering Company that a section 311(b) price ceiling is acceptable).

[9] Further Comments of the Department of Energy submitted May 7, 1979, page 11.

[10] "[M]any residential, commercial and small industrial fuel oil customers will be particularly affected by high-priced and possibly inadequate distillate fuel oil. It is this Commission's responsibility to afford these users, who would be considered 'high priority' if served by natural gas, relief within our discretion so long as this relief does not come at the expense of other high priority users." Order No. 30 at page 7.

[11] Further Comments of the Department of Energy, submitted May 7, 1979, at page 2.

[12] The Commission does not feel that it is necessary to exclude imported natural gas from the program. To the extent that it backs out middle distillate fuel oil, it furthers that policy goal of Order No. 30; to the extent that it backs out imported oil, it benefits our nation's balance of payments problem, (because it must be cheaper than oil to be attractive to users, fewer dollars are exported) and reduces our nation's demand for imported oil at a time of reduced international supplies of oil.

[13] Comments of Consolidated Edison, May 1979 at 2.

[14] Docket Nos. CP79-214, *et al.*, CP79-228, and CP79-304.

[15] Notice of Proposed Rulemaking, 44 FR 17644 (March 27, 1979).

[16] BUG, Application for Rehearing at 7.

[17] Natural Gas Act section 7(e), 15 U.S.C. 717f(e).

[18] A pipeline or distribution company subject to a curtailment plan could sell gas directly to an end-user (a nonjurisdictional sale under the NGA), and have the gas transported under section 311(a). Unless the section 311(a) transaction is examined, the entire transaction could go forward in contravention of the applicable curtailment plan.

[19] The ERA proposed the rule at 44 FR 17644 (March 22, 1979). The Commission then established comment procedure on the ERA proposal 44 FR 21682 (April 11, 1979).

[20] Statement of John O'Leary, Tr. at 23.

[21] *See*, Notice of Proposed Rulemaking issued July 2, 1979 in Docket No. RM79-24.

[¶ 30,085]

44 F. R. 57726 (October 5, 1979)

18 CFR Parts 154, 201, 204, and 282

[Docket No. RM79-14; Order No. 49]

Regulations Implementing the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts regulations that implement the incremental pricing provisions of the Natural Gas Policy Act of 1978. Under the incremental pricing program, large industrial facilities which burn natural gas as a boiler fuel will be priced for that gas at a level equivalent to the price they would pay for fuel oil which they could burn as an alternative to natural gas. Those regulations provide the regulatory framework for the calculation and billing of incremental pricing surcharges to facilities subject to the incremental pricing program. The regulations also set forth the procedures by which an industrial facility may obtain an exemption from the program.

EFFECTIVE DATE: November 1, 1979, *provided that*, the provisions of 18 CFR 282.201-206 shall be effective October 15, 1979.

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Regulations Implementing the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978.

Issued: September 28, 1979.

I. Background

Title II of the Natural Gas Policy Act of 1978 (NGPA) (Pub. L. 95–621) requires that interstate pipelines and local distribution companies pass through certain portions of their natural gas acquisition costs to industrial users in the form of surcharges. These surcharges may not, however, raise the ultimate cost of gas to the user above the cost of the fuel oil which could be used as an alternative to natural gas.

The incremental pricing program is to be implemented in two phases. The only facilities affected during the first phase will be those using natural gas as fuel for large industrial boilers. Title II requires that the regulations implementing this first phase be promulgated by November 9, 1979.

During the second phase of the program, incremental pricing may be extended to a broader class of industrial users than those affected by the first stage. The NGPA sets May 9, 1980, as the date for the regulations implementing the second phase and establishes that those regulations will be subject to Congressional review and possible disapproval by either House.

Two rulemaking dockets were established to promulgate the regulations needed to implement the first phase of incremental pricing, Docket Nos. RM79–14 and RM79–21. A companion document to this final rule is being issued in Docket No. RM79–21.[1] The background of the proceeding in Docket No. RM79–21 is described in the final rule in that docket.

A Notice of Proposed Rulemaking and Opportunity for Written and Oral Presentations of Data, Views and Arguments in this docket was issued on June 5, 1979 (44 FR 33099, June 8, 1979) in order to propose regulations for the implementation of those provisions of Title II of the NGPA not encompassed by Docket No. RM79–21. These proposed regulations covered revisions to the Commission's historical method of calculating rate changes pursuant to purchased gas costs adjustment (PGA) clauses, the actual calculation and billing of incremental pricing surcharges, and the accounting provisions necessary for the implementation of the program. In addition, the proposed regulations set forth procedures to be utilized by facilities seeking to obtain exemptions from the incremental pricing program.

The approach set forth in the June 5th Notice for the calculation and billing of incremental pricing surcharges, the "surcharge mechanism," was developed after two informal conferences were held to give interested parties the opportunity to comment on preliminary proposals for the mechanism. Those conferences were held in February and April and were convened to discuss, respectively, a staff proposal issued January 12, 1979, (44 FR 6133, January 31, 1979) and several alternative proposals offered by various interested parties.

A public hearing on the June 5th proposal was held in Washington, D.C. on June 27, 1979. Nineteen interested parties presented comments at this hearing, including representatives of interstate pipelines, distribution companies, associations whose membership includes both pipeline companies and distribution companies, a consumer group and an industrial end-user group. A total of sixty-nine written comments were submitted in response to the June 5th Notice. The transcripts of the informal conferences, the June 27th hearing and all written comments submitted to the Secretary of the Commission in this docket have been made a part of the record in this proceeding. The Commission has reviewed all portions of this record in developing the final rule in this proceeding.

The regulations encompassed by this docket are lengthy and quite detailed. The comments submitted in this docket were generally excellent and very helpful. The discussion which follows seeks to fully explain how the regulations set forth below differ from those included in the June 5th proposal, as well as to respond to many of the suggestions that were raised in the comments submitted but which have not been incorporated in the final regulations.

II. Commission Jurisdiction

Title II of the NGPA significantly expands the jurisdiction of this Commission in comparison to the authority vested in the Commission pursuant to the Natural Gas Act. Title II brings within the purview of this Commission's jurisdiction for the first time all local distribution companies that receive supplies of natural gas from interstate pipelines. A definition of "local distribution company" has been added to the definitions section of the regulations below, § 282.103, in order to clarify exactly which companies are governed by the provisions of the regulations. The definition below differs from the definition of "local distribution company" set forth in the NGPA. However, this definition is adopted so that the one term, "local distribution company" may apply, for purposes of the incremental pricing regulations, to all companies, other than interstate pipelines, to which Congress intended Title II should be applicable. The intent of Congress in this regard is set forth in the Statement of Managers on the NGPA:

> The application of this rule is limited to boiler fuel facilities served by an interstate pipeline, and those served by a local distribution company that is served by an interstate pipeline. The term interstate pipeline is meant to include those pipelines which are subject to the jurisdiction of the Commission under the Natural Gas Act. "Hinshaw" pipelines, which are not subject to the Commission's jurisdiction under sec. 1(c) of the Natural Gas Act, are considered local distribution companies, for purposes of incremental pricing, to the extent that they are served by an interstate pipeline.[2]

Local distribution companies, as defined in § 282.103, as well as interstate pipeline companies, are required to comply with the regulations set forth below. The Commission anticipates that the Title II regulations will be enforced with equal emphasis as they apply to interstate pipelines and local distribution companies. In this regard, section 504 of the NGPA is noted. Under the provisions of section 504, violations of these regulations will be subject to civil and criminal penalties.

III. The Basic Mechanism: The "Reduced PGA" Approach

The basic approach for the calculation and billing of the incremental pricing surcharges has received significant and detailed discusion in this proceeding since the issuance of the initial staff proposal of January 12th. That proposal was structured so that incremental pricing surcharges would not be billed until 4 to 10 months after the actual incurrence of the costs to be passed through by way of surcharges. As a result of the February and April informal conferences, Commission staff determined to accept a recommendation made by the United Distribution Companies (UDC), Northern Natural Gas Company (Northern) and Natural Gas Pipeline Company of America (Natural) and to develop a mechanism which would allow for the recoupment of surcharges by suppliers at a time proximate to the time at which they must pay their own suppliers for gas deliveries which give rise to the surcharges.

The method suggested by UDC, Northern and Natural was to permit pipeline companies to estimate in advance their total gas acquisition costs and the portion of those costs which would ultimately be recovered by way of incremental pricing surcharges. The estimated surcharge recovery would be subtracted from the estimated total gas acquisition costs, and this "reduced" gas acquisition cost estimate would be recovered through the purchased gas costs adjustment (PGA) rate.

This reduced cost estimate would then form the basis of the PGA rate for all customers on a pipeline's system. Industrial customers included in the incremental pricing program would be billed on the basis of this reduced PGA rate, plus an incremental pricing surcharge.

An alternative to the "reduced PGA" approach was suggested by the Interstate Natural Gas Association of America (INGAA) at both the February and April informal conferences. This method would involve billing all customers on the basis of the normal PGA rate—which would reflect inclusion of all gas acquisition costs. Industrial customers included in the program would be billed an appropriate incremental pricing surcharge, while a corresponding credit would be extended to all other customers. The total of the credits would equal the amount recouped by way of surcharges.

The "INGAA method" received serious consideration by the Commission, but was not the approach eventually chosen and set forth in the June 5th proposed regulations. The Commission stated in the June 5th Notice that it believed that the "reduced PGA" approach would result in a "less burdensome regulatory program for all affected parties."

The Commission noted in the June 5th proposal, however, that it was continuing to consider the "INGAA method" and invited further comments as to whether that method should be adopted.

The comments submitted in response to the June 5th Notice were overwhelmingly in favor of the "reduced PGA" approach. On the basis of the record, the Commission adopts as a final rule the "reduced PGA" method of calculating and billing incremental pricing surcharges.

The "reduced PGA" method embodied in the final regulations will operate as follows. Each interstate pipeline will, prior to filing its revised PGA tariff sheet for an upcoming PGA period, estimate the total amount of gas acquisition costs it will incur during the upcoming PGA period. A pipeline will be permitted to take into account, when projecting its total gas acquisition costs for a coming period, increased costs anticipated due to price increases permitted to producers under the provisions of the NGPA. A pipeline will not, however, be permitted to take into account when making this projection any volume of supply which would not be attached to the system as of the date the new rate will take effect. Each pipeline will also estimate the portion of its projected total gas acquisition costs that will be "incremental costs" and thus subject to being passed through as incremental pricing surcharges.

The pipeline will then project the total maximum surcharge absorption capability (MSAC) of the non-exempt industrial boiler fuel facilities which will be served, directly or indirectly, by the pipeline.

The MSAC is the key element of the incremental surcharge passthrough mechanism. In simplest terms, it is the total difference between the cost of gas to a facility and the ceiling on incremental pricing which is applicable to the facility, i.e., the total amount of incremental cost the facility can absorb before its price of gas will rise above the applicable ceiling.

In order for a pipeline to develop its projected MSAC, each local distribution company will estimate the MSAC of each of its incrementally priced customers and report a total projected MSAC to its supplying pipeline. The projected MSAC of an individual industrial boiler fuel facility will be calculated in accord with the formula set forth in § 282.503 of the regulations. In those cases where a local distribution company is supplied by more than one pipeline, the total projected MSAC of the distribution company will be prorated among its suppliers in accord with a formula set forth in the regulations.

Each supplying pipeline, in turn, will add the projected MSAC's reported to it by the distribution companies it serves and add thereto the total projected MSAC of all non-exempt industrial boiler fuel users it serves directly. This pipeline will then report its total projected MSAC to its supplying pipelines on a prorated basis.

This reporting will continue until the most "upstream" pipeline has received reports from all the interstate pipelines and local distribution companies served by it. After adding to the reported MSAC's the projected MSAC's of its own direct sale customers, this pipeline will compare its total projected MSAC to its total projected gas costs subject to surcharge passthrough for the coming PGA period. The pipeline will use the lesser amount to reduce its total estimated gas acquisition costs for the coming PGA period in order to derive a "reduced PGA" rate for the period.

The pipeline will file this "reduced PGA" rate with the Commission and use this rate for the following PGA period. As a result, there will be an immediate flow-through of the estimated benefits of incremental pricing to the residential and small commercial customers, since their gas rates will reflect the pipeline's "reduced PGA" rate.

Non-exempt industrial boiler fuel users will be billed on the basis of the "reduced PGA" rate. In addition, however, they will be billed an incremental pricing surcharge. The surcharges will be based on actual usage and actual alternative fuel price ceilings established for the month in which usage occurs.

In order to determine surcharges for both individual customers and sale-for-resale customers, actual MSAC's will be calculated for each industrial facility, local distribution company, and interstate pipeline. All information will be passed from resale customers to suppliers until the most "upstream" pipeline supplier has received reports from all customers on its system. It will then compare the total MSAC of its system for the past month to the total incremental gas acquisition costs it incurred during that month.

If the total incremental acquisition costs are less than the total MSAC, the "upstream" pipeline will bill surcharges on the basis of each customer's pro-rata share of the incremental gas costs. Each customer, in turn, will bill its customers a pro-rata share of the amount it has been surcharged, until each end-user is ultimately billed a surcharge.

If, however, the total incremental acquisition costs are greater than the total MSAC, the "upstream" pipeline will bill surcharges in the amount of the MSAC's. Each customer, in turn, will bill on the basis of its customers' MSAC's.

Any incremental acquisition costs which the "upstream" pipeline does not recover may be recovered in the following PGA period, just as under the present PGA system, since the unrecovered balance will be cleared to account 191, Unrecovered Purchased Gas Costs, following the billing of incremental pricing surcharges each month.

Incremental gas acquisition costs may be incurred directly by local distribution companies, as well as by interstate pipelines. To the extent that, due to the incremental pricing ceiling, those costs are not fully recovered through incremental pricing surcharges, they may be recovered in whatever manner is permitted by the appropriate State or local authority having jurisdiction.

IV. Billing Procedures

A. Meter Reading Cycles

In its June 5th Notice, the Commission proposed to require that the meters of incrementally priced industrial users be read on or about the 20th of each month. This aspect of the mechanism was intended to allow sufficient time for the communication of all information necessary for the calculation of surcharges between the end of the billing month and the normal date on which its was believed suppliers render bills to their industrial customers, i.e., the 10th of the following month. The 20th of the month billing period was based on representations made at the April conference with respect to the industry practice of billing industrial customers on a calendar month basis.

However, the majority of comments offered in response to the June 5th proposal criticized the proposed imposition of a uniform billing period ending on the 20th of the month. Many suppliers stated that industrial customers are billed on a cyclical basis in much the same manner as are high priority customers. Thus, to require the meters of all such customers to be read on the same day would disrupt present meter reading and billing practices.

In the course of analyzing the comments on this issue, Commission staff determined that the 20th of the month approach would effect another undesirable result. Under this method, the incremental pricing surcharges billed to many industrial customers for any given billing period would not reflect the acquisition costs incurred by their suppliers for the volumes delivered during the period for which the surcharge was calculated.

In order to avoid the imposition of one mandatory meter reading date and to address the problem identified by Commission staff, the following approach has been developed. The regulations set forth below treat a standard calendar month as a billing period. The regulations provide that meters of incrementally priced industrial users shall be read on or before the last day of a calendar month, but may not be read any more than 10 days prior to the end of the month. The limitation of meter readings to the last 10 days of any month carries out our goal of having incremental pricing surcharges reflect as closely as is administratively feasible a supplier's costs for the volumes delivered during the period for which the surcharge is calculated.

This approach will also, we believe, result in the least disruption of current meter practices that would be possible in order to achieve our goal of matching acquisition costs with surcharges. Under the approach, meters of incrementally priced industrial users may be read during a 10-day period of the month. Theoretically, at least one-third of the users on any system are already being read during this period of the month. Given the relatively small number of such users on a system, we believe the rescheduling of meter readings of at most two-thirds of those users should not be a significant burden.

To implement this approach, a provision has been added to § 282.501 which requires that the MSAC of an incrementally priced industrial user for any one calendar month be calculated on the basis of the meter reading made in the last ten days of that month. Meter readings made in the final ten days of any calendar month will be deemed to represent usage for that month. The alternative fuel price ceilings applicable for the calendar month will be utilized to calculate the MSAC's and surcharges applicable to volumes which are covered by the meter readings made in such period.

As set forth in the regulations promulgated in Docket No. RM79-21, the alternative fuel price ceilings applicable for a calendar month will be published no later than the 20th day of the preceding month. Thus, end-users will know the price they potentially will have to bear for their use of natural gas in any month prior to the beginning of that month.

It should be noted that the first meter readings made pursuant to the regulations below, in January, 1980, may reflect a few days of usage during December, 1979, which would not be subject to being incrementally priced. Any such readings should be pro-rated in order to avoid pricing non-exempt users incremental surcharges for their use of gas prior to January 1, 1980.

B. *Time Permitted for Exchange of Information*

As noted above, the primary reason for the 20th of the month billing period proposal was to permit sufficient time for the exchange of information between suppliers and their customers in order to calculate surcharges by the normal billing date for pipeline suppliers. However, many commenters stated that even 20 days—from the 20th of one month to the 10th of the next—would not be adequate for the collection of all necessary information and the calculations needed to compute incremental pricing surcharges. This view was expressed primarily by suppliers that serve a large number of industrial facilities for which surcharges will have to be calculated and who themselves receive gas from several suppliers.

However, those suppliers which have a relatively small number of customers on their systems that will be subject to the first phase of the incremental pricing program and who themselves have a small number of suppliers typically stated that the exchange of information and calculation of surcharges could be accomplished within a 20-day time frame.

Two optional billing procedures are described below which will, we believe, provide adequate time for the exchange of all needed information. In addition, they will allow us to adopt the less disruptive "calendar month" approach described above. Either of the two procedures may be utilized in lieu of billing in accord with the time sequence set forth in the regulations, since the regulations will only provide 10 days for the exchange of information between the end of a month and the typical 10th of the month billing date.

INGAA was a primary spokesman for the position that 20 days would not be adequate for all needed communication and calculations to arrive at the actual surcharges which must be billed under the "reduced PGA" method. INGAA also suggested a solution to this timing problem which appears to be workable. The Commission has determined to adopt INGAA's proposal with respect to sales of natural gas made by interstate pipelines to sale-for-resale customers.

Under this method, an interstate pipeline will have the option of billing a sale-for-resale customer a surcharge for any one calendar month equal to the surcharge estimate which the pipeline used for the customer in order to derive the pipeline's currently effective reduced PGA rate. In the following month, the bill rendered to that sale-for-resale customer will be adjusted by an amount to reflect the difference between the surcharge billed the previous month and what that surcharge should have been, as calculated from actual usage figures and actual alternative fuel price ceilings.

This method will have the effect of allowing a total of up to 40 days for the exchange of information and calculation of surcharges. The Commission believes this time period should be adequate for the passage of required information on even the most complex supply system covered by this Phase I rule.

The regulations below also incorporate the alternative feature which was included in the June 5th proposal with respect to billing by local distribution companies of industrial boiler fuel facilities. Under this alternative, a local distribution company may bill any non-exempt industrial boiler fuel facility it supplies at the level of the alternative fuel price ceiling which is applicable to the facility, and adjust the following month's billing for any resulting overrecovery.

With respect to this alternative, we have altered the final regulations below somewhat from the proposal in that the regulations require any overrecovery to be refunded to the facility from which it was collected. Our proposal indicated that state or local authorities would have jurisdiction as to these refundable amounts. We have been persuaded, however, by several comments submitted on this point that our regulations should require a refund to the party who paid the original amount. Otherwise, the optional billing procedure might result in inequitable treatment of some users. We believe that this requirement does not impinge on state or local jurisdiction, since incremental pricing surcharges are uniquely subject to Federal jurisdiction.

According to all estimates submitted to the Commission since it began considering implementation of Phase I of the incremental pricing program, from the inception and throughout Phase I, gas acquisition costs subject to passthrough by incremental pricing surcharges will exceed the aggregate surcharges which can be passed through to industrial end-users which are not exempt from the program. Thus, industrial users in most cases will be billed surcharges which bring the price of gas up to the level of the alternative fuel price ceilings. In all situations where this will be the case, the two optional billing procedures described above, as compared to billings based on actual data, should not result in any significant difference for affected end-users with respect to the timing of payments.

Furthermore, for those systems as to which all calculations can be made on a current basis, the regulations provide the flexibility for billings to reflect actual data.

V. Calculations Required Under the "Reduced PGA" Approach

The two formulas required to calculate incremental pricing surcharges under the "reduced PGA" approach were set forth in the regulations proposed on June 5th. Each formula was set forth in a projected and actual variant, in §§ 282.503 and 282.504 of the regulations, respectively.

A. MSAC Formula

The formula for the calculation of the maximum surcharge absorption capability (MSAC) of an individual industrial facility was set forth in symbols in §§ 282.503 and 282.504. This formula will be utilized to determine the amount of surcharge which can be passed through to a particular facility before the price of natural gas delivered to the facility rises to the computed price of the alternative fuel which the facility can use.

Several commenters noted that the formula which was proposed on June 5th did not include a variable for state or local taxes which would be applicable to the surcharge. The proposed formula did encompass state or local taxes levied on the price paid for volumes of natural gas were it not for incremental pricing surcharges. However, the formula did not include a variable which would permit appropriate adjustment of the MSAC in those cases where a state or local tax will be levied on the additional amount which will be represented by the surcharge.

The Commission agrees with the comments which noted this point and has adopted the changes to the proposed MSAC formula suggested by these commenters. Therefore, the formulas for a projected MSAC set forth in § 282.503 below and for an actual MSAC, set forth in § 282.504, have been amended from those which were proposed by adding a denominator which will serve to reduce the MSAC by any tax which may be levied on the surcharge. Thus, the surcharge calculated on the basis of this MSAC will be of an amount that will not include the tax which will be added to the surcharge when it is billed to the industrial end-user. These formulas, as revised, will ensure that natural gas costs to non-exempt users will not exceed their alternative fuel costs.

B. Prorating of MSAC

Many commenters disagreed with the formula which was proposed to allocate a total MSAC of a purchaser/supplier among its several suppliers. With respect to volumes of gas which it either purchases directly or produces itself, a pipeline company or distribution company could only take into account under the proposed prorating fraction, in prorating the MSAC on its system to its various suppliers, those volumes of gas which carry incremental gas acquisition costs. However, the formula would permit a pipeline or distributor to take into account in the prorating fraction all volumes of gas which it purchases from an interstate pipeline, irrespective of whether such volumes carry incremental acquisition costs.

Interstate pipelines argued that the supply purchased from sources other than interstate pipelines and that supply which is the pipeline's own production should not be limited to only those volumes which carry incremental costs. Several local distribution companies also argues that their total supply should be utilized in the calculations.

We have given careful consideration to all of the comments submitted on this question. We have, however, determined to adopt the prorating fraction as it was proposed, for the reasons discussed below.

We recognize that our proposed formula involves a different treatment of purchases from other pipelines as compared to direct purchases or production of the pipeline in question. Our determination to adopt this approach is a conscious one based on administrative feasibility.

Several commenters stated that the proposed formula would create a situation where, on a total system, the exempt and non-exempt customers of "downstream" pipelines would end up bearing more than their fair share of incremental gas costs as compared to the customers of "upstream" pipelines. Stated another way, these commenters argued that the proposed formula would result in a shifting of "upstream" pipeline incremental gas costs into "downstream" pipelines' PGA's.

We agree that the prorating set forth in the regulations below could effect such a situation in the case where the incremental costs on a system are less than the MSAC on that system. However, where the converse is true—and, as stated elsewhere in this preamble, the record in this proceeding indicates that the converse situation will be the norm—all non-exempt users on a system will be able to absorb a surcharge in the amount of their MSAC, without absorbing all the incremental costs incurred by the suppliers on the system. Therefore, all such users will be surcharged at the level of the alternative fuel price ceiling from the outset of the program. Under our prorating fraction, no one pipeline or distributor will have to absorb a greater surcharge from each of its suppliers than it is able to pass on to its customers.

However, under the approach urged by the commenters, a pipeline or distributor would effectively shield a portion of the MSAC on its system. This result would occur because the MSAC prorating fraction is designed to result in an amount which, when multiplied by the total MSAC on a system, will represent the amount of the surcharge which a pipeline or local distribution company can absorb from a given supplier. If volumes were included in the denominator of that fraction with respect to which no incremental acquisition costs must be recouped, the larger denominator would result in a smaller MSAC to be reported to the supplier(s).

To the extent a pipeline or distributor could shield a portion of the MSAC on its system, it would be able to price its industrial users, on the average, below the applicable alternative fuel price ceilings.

The ideal approach would be to base the allocation of MSAC's strictly on incremental costs associated with the volumes delivered to any one pipeline or distribution company. This, however, would require a reporting burden of enormous complexity and magnitude. To avoid such a burden, we have opted for an approach which necessitates a certain degree of approximation. Specifically, this approximation involves the reporting "up" a system of supply the MSAC's of each level in the system, and the billing "down" the chain the incremental surcharges based on those MSAC's.

We believe the only alternative to the approach described here would be to adopt the approach to the billing of incremental pricing surcharges proposed in the original January 12th staff proposal—i.e., to compute surcharges on the basis of actual data. We believe that the comments submitted in this proceeding, and especially on the January proposal, have established that a mechanism based on actual data is undesirable and thus not a viable alternative.

The primary differences between the treatment of interstate pipelines and local distribution companies in the prorating fraction is that local distribution companies will not be permitted to include any volumes of its own production of "new" gas therein. No portion of the prices or costs associated with such production are required to be booked into the incremental gas costs account and thus no portion of such costs is subject to passthrough as a surcharge to non-exempt industrial facilities.

One commenter suggested that local distribution company production be treated identically to interstate pipeline production—i.e., that incremental costs be imputed thereto which would then be passed through by way of surcharges. However, the Commission has found no provision in Title II which would lead it to believe or conclude that the Congress intended identical treatment of the production of the two different entities under the regulations implementing Title II.

Specifically, section 203(b)(2) of the NGPA requires that the Commission prescribe rules to determine the "first sale acquisition costs" of natural gas produced by an interstate pipeline. Such "first sale acquisition costs" are then used to determine the portion of the costs subject to being passed through as incremental pricing surcharges. The Congress did not, however, give the Commission similar authority with respect to the production of local distribution companies.

Thus, local distribution companies will include all supplies purchased from interstate pipelines and all supplies purchased from other sources which are within one of the categories described in paragraphs (a) through (k) of § 282.301 in calculating the volume to be used in the denominator of the prorating fraction.

It is appropriate to note here the requirement of section 204(c)(4) of the NGPA. This section states:

> Sec. 204(c)(4) LOCAL DISTRIBUTION COMPANY DIRECT PURCHASES.—In any case in which a local distribution company directly incurs any first sale acquisition cost subject to the passthrough requirements of this title under section 203 or otherwise directly incurs any other cost subject to such requirements under sections 203(a)(8)(B), (9) or (10), such local distribution company shall, with respect to the natural gas involved, be treated for purposes of this title as if it were an interstate pipeline.

Pursuant to this section, any local distribution company that purchases natural gas the price of which is governed by Title I of the NGPA or makes certain other purchases, such as pursuant to the regulations which implement section 311 of the NGPA, is deemed to be an interstate pipeline with respect to those purchases for purposes of the incremental pricing program. Thus, such a company must book into its accounts the portion of the costs of such gas which is subject to passthrough as a surcharge to non-exempt industrial users and must calculate surcharges in accord with the regulations set forth below.

C. Estimated Alternative Fuel Price Ceilings

Several commenters urged that alternative fuel price ceilings be estimated and published at some point this fall for the use of suppliers in projecting MSAC's for individual non-exempt industrial boiler fuel facilities and thus total MSAC's for distribution systems. Pipelines will need these estimates in order to estimate the amount by which their total projected gas acquisition costs can be reduced for purposes of filing reduced PGA rates with this Commission by December 1, 1979.

The Commission is sympathetic to the request that an official estimate of alternative fuel price ceilings would be helpful for the initial estimates required by the regulations below. However, it is anticipated that, as set forth in Docket No. RM79-21, the Energy Information Administration (EIA) of the Department of Energy (DOE) will be the agency which will publish the alternative fuel price ceilings on a monthly basis. We have inquired of the EIA as to whether ceilings could be estimated and published prior to the publication of actual ceilings in mid-December for January, 1980. EIA has stated that it will not be possible to calculate actual ceilings—i.e., ceilings based on collected data—any earlier than mid-December. Further, EIA believes any estimates it might undertake to calculate would be very judgmental.

We believe that pipeline companies and distribution companies will be able to ascertain at least an approximation of fuel oil prices in their service areas which can be utilized for the first series of estimates. Thus, the solution which appears to be most equitable to all parties concerned is to place the discretion in every supplier subject to these rules to utilize estimates of its own choice for the first round of calculations. Furthermore, as explicitly set forth in the regulations, an interstate pipeline is required to provide assistance to any local distribution company it serves in making estimates on alternative fuel price ceilings, if the distribution company so requests.

D. Flat Amount vs. Per Mcf Surcharge

Both the January staff proposal in this docket and the June proposed regulations provided for the calculation of incremental pricing surcharges in flat dollar amounts, rather than on a cents-per-Mcf basis.

The Office of Oil and Gas Policy of the Office of the Assistant Secretary for Policy and Evaluation of the DOE submitted in this docket an analysis of the effect of the two differing methods on various users on a distribution system. That analysis concludes that the two methods do not have different effects once all non-exempt users reach their alternative fuel price ceilings.

During the interval in which some non-exempt industrial end-users are below their alternative fuel price ceilings, the two methods can result in differing effects. End-users which had been paying a lower rate, when compared to other users on the system, prior to establishment of the incremental pricing program would absorb a greater share of the incremental gas costs borne by its supplies under the flat-dollar amount method. These end-users would thus receive a comparatively greater per Mcf rate increase. Those users which had previously paid a higher rate would absorb a smaller portion of the incremental gas costs, or surcharge, borne by its supplier, and thus incur a lower per Mcf rate increase.

As noted by the DOE, however, this difference does not exist once all non-exempt users reach their alternative fuel price ceilings. And, the flat-dollar amount approach results in all users reaching that ceiling at the same time.

This Commission agrees with the DOE's analysis as presented. However, we maintain our original position with respect to this question. Specifically, we believe that a per Mcf approach would be unduly complex from an administrative point of view and that the benefits of that approach do not justify its burdens. The cents-per-Mcf approach would involve much more complex calculations than are required for the approach which has been adopted. Only one other comment in this docket discussed this point, and stated that a cents-per-Mcf approach could cripple the program.

As the DOE analysis indicates, the two methods differ only when incremental gas costs are less than the absorption capability of a particular system. As stated elsewhere in this preamble, all data submitted to date in this docket indicates that non-exempt industrial boiler fuel users will be priced at the alternative fuel price ceilings upon implementation and thoughout Phase I of the program. If experience under the program indicates that the phenomenon analyzed by DOE is in practice a serious problem, we shall review the flat-dollar surcharge approach.

VI. Exemptions

A. In General

Pursuant to sections 206(a), (b) and (c) of the NGPA, natural gas used by small existing (as of November 9, 1978) industrial boiler fuel facilties, agricultural users, schools, hospitals and certain other facilities is exempt from being incrementally priced.

Although these exemptions are granted by the terms of the statute, there still remains the necessity of identifying precisely which facilities qualify under the categories set forth. The Commission proposed in the June 5th Notice to untilize a self-certification procedure for this purpose, similar to the self-certification procedure to be used for the establishment of the alternative fuel capability of an industrial facility, included in the regulations in Docket No. RM79-21.

No comments criticized this approach for the identification of exempt facilities. Thus, the exemption affidavit procedure that was proposed has been adopted in substance in the final regulations set forth below.

The procedure involves essentially two steps. To minimize the burden on industrial end-users, a natural gas supplier is required to first identify from its records which facilities served by it are industrial boiler fuel facilities—that is, industrial facilities which burn natural gas as boiler fuel. The supplier is then to identify from its records, if possible, which of these facilities meet the two-pronged test for an existing small boiler, or, in other words, an exemption pursuant to the terms of section 206(a)(1) of the NGPA. The statute prescribes that a small boiler facility is one which was in existence on the date of enactment of the NGPA—November 9, 1978—and which did not use more than an average of 300 Mcf per day of natural gas as boiler fuel during any month of a base period selected by the Commission. The Commission has determined to use calendar year 1977 as the appropriate base period for purposes of this so-called "interim exemption" for small boilers.

If a supplier can make the above determinations from its records, it need not send an exemption affidavit to a facility thus deterimined to be exempt. The natural gas supplier is required to send an exemption affidavit to all other industrial boiler fuel facilities which it has identified in reviewing its customer list.

B. Exemption Affidavits

The exemption affidavit has been designed by Commission staff and must be used by suppliers in fulfilling their responsibility under the regulations. Copies of the affidavit are available from the Commission's Washington, D.C. Office of Public Information at 825 North Capitol Street, N.E., Room 1000, Washington, D.C. 20426, or upon a telephone request. The telephone number of this office is (202) 357-8055. A copy of the final version of the exemption affidavit is appended to this preamble.

One commenter suggested that a question be added to the affidavit to permit an industrial user to certify that all of its natural gas is used for exempt commercial purposes. We agree with this comment and recognize that a supplier's records might not indicate what otherwise would appear to be an industrial boiler fuel facility is not such a facility.

Therefore, a question has been added to the affidavit which will permit a natural gas user to establish via the affidavit procedure that his facility is not an industrial facility, as defined in the regulations below, which burns natural gas as a boiler fuel.

One commenter suggested that the regulations require that all affidavits be returned to natural gas suppliers. We proposed to require return by only those users who are entitled to an exemption in whole or in part from the incremental pricing program. Users not eligible for a total or partial exemption would not return the affidavits to their suppliers.

The Commission has given careful consideration to this aspect of the exemption procedure and has determined to adopt the approach which was proposed. We believe this approach is consistent with that of other programs which provide for exemptions—that only those desiring the benefit of an exemption should be required to complete some form of an application.

Further, since we are eliminating the annual reaffirmation requirement with respect to exemptions (see discussion below), this approach should not place an undue burden on any natural gas user.

The June 5th proposal contained provisions which would have required natural gas suppliers to make copies of executed exemption affidavits available at their business offices. In addition, suppliers would have been required to make available to the public lists of non-exempt facilities which they are required to compile and file with the Commission.

Many commenters objected to any regulation which would require natural gas suppliers to make available to the public information on the exempt or non-exempt facilities served by that supplier. The Commission has been persuaded by the comments submitted on this topic in both this docket and its companion, RM79-21, that this burden should not be placed on natural gas suppliers. Therefore, we have amended all provisions on public availability of such information.

Natural gas suppliers will be required, however, to send copies of the non-exempt lists required by § 282.204(e)(2) to state or local commissions, in addition to this Commission, in all those instances where such commissions exist having appropriate regulatory jurisdiction. These lists will be available for public inspection at the Commission's Washington, D.C. Office of Public Information. State or local commissions which receive such lists may also make them available for public inspection, if they so choose.

Some commenters also expressed concern about the divulgence of confidential business information if the exemption affidavits are open to public inspection. The Commission does not believe that any of the information which will be included on the exemption affidavits is of a confidential nature. However, if any party completing an affidavit believes differently, he may petition the Commission under the regulations which implement section 502(c) of the NGPA for an adjustment to the regulations governing public inspection of exemption information.

C. Reaffirmation Affidavits

The Commission proposed in the June 5th Notice to require that exemption affidavits be updated, or reaffirmed, on an annual basis, as a means of identifying those facilities which no longer use gas for a statutorily exempt purpose. The Commission believes such facilities should not be entitled to retain their exemptions from the incremental pricing program.

Although it was proposed to require that reaffirmation affidavits be filed on an annual basis, comments were specifically requested on an alternative approach of requiring end-users to inform their suppliers and the Commission of a change in circumstances which would disqualify a facility for an exemption.

The majority of comments addressing this issue stated that the annual reaffirmation procedure would be administratively burdensome. They further stated that requiring the end-user to notify its supplier and the Commission should the use of the facility change from an exempt to a non-exempt status would be sufficient to accomplish the desired goal. One commenter noted that natural gas suppliers are typically familiar with their customers and would know if the owner of a facility was not conducting himself with candor.

The Commission is persuaded that the annual filing of a reaffirmation affidavit is not necessary for successful operation of this program and that it would place an unnecessary burden on industrial users of natural gas. Therefore, the regulations set forth below include a provision, § 282.205, which requires an industrial user of natural gas to inform its natural gas supplier and the Commission if the use of a previously exempt facility changes so that the facility should be incrementally priced with respect to its boiler fuel use of natural gas. Following such notification, of course, the facility will be billed incremental pricing surcharges in appropriate amounts.

Among the comments on this issue was a suggestion that, if a change of circumstances regulation was adopted in lieu of the reaffirmation requirement, the regulations include a sanction for non-compliance. We believe such a provision is unnecessary, but note again the civil and criminal penalities which may be levied under section 504 of the NGPA for noncompliance with regulations which implement the NGPA.

D. Agricultural Use

Section 206(b) of the NGPA requires that the Commission provide an interim exemption from the regulations adopted in Phase I of the incremental pricing program "to the extent of any agricultural use of natural gas" by an industrial facility. This interim exemption is to remain effective until such time as the statutorily required "permanent exemption" for agricultural use becomes effective.

The provision of the June 5th proposed regulations which provided for the agricultural use exemption was § 282.203(b). The definition of "agricultural use" was set forth in the proposed § 282.202(5). This definition was to be utilized in conjunction with the exemption affidavit. The definition proposed was as follows: "Agricultural use" means any use of natural gas which is certified by the Secretary of Agriculture under 7 CFR § 2900.3 as an 'essential agricultural use' pursuant to section 401(c) of the NGPA."

Several commenters argued that this definition should be broadened to be consistent with the definition of "agricultural use" contained in section 206(b)(3) of the NGPA. The commenters pointed out that the 206(b)(3) definition is different from the definition of "essential agricultural use" set forth in section 401(f)(1) of the NGPA, in that the latter definition, while encompassing the same end uses of natural gas, requires the Secretary of Agriculture to further define the agricultural uses of natural gas which are "necessary for full food and fiber production."

The commenters argue that the Secretary of Agriculture's rule, which determines essential agriculture uses, was intended to be used for curtailment priorities only, and not for purposes of determining "any agricultural use" under section 206(b) of the NGPA. One commenter noted that the Secretary of Agriculture, in the preamble to the final rule which certifies essential agricultural uses, expressly recognized that the rule "should not be construed as any indication of what is or is not an 'agricultural use' for purposes of other sections of the NGPA, notably section 206." (44 FR 28784, May 17, 1979.)

Furthermore, one comment pointed out that the language used in the statute, in the Statement of Managers, and in the floor debates consistently maintains a distinction between "any agricultural use" for purposes of incremental pricing and an "essential agricultural use" for purposes of curtailment priorities in section 401 of the NGPA.[3]

The American Textile Manufacturer's Institute (ATMI) argued that the use of natural gas as a boiler fuel in textile manufacturing operations should be considered an "agricultural use", since the manufacture of textiles (insofar as natural fibers are involved) is "natural fiber production and processing".

ATMI noted that, in the Department of Agriculture's final rule, the Secretary of Agriculture determined that the textile industry was not included as an essential agricultural use because, although it would be "eligible for consideration on the basis of being a use for natural fiber processing," such use is not "necessary for full food and fiber production." (44 FR 28784, May 17, 1979)

As ATMI pointed out, the initial stage of textile manufacturing involves the processing of fibers (including natural fibers) for the production of fabric by spinning and weaving or knitting. In the next stage, most textile fabrics move through finishing mills for purposes of adding characteristics such as color, napping, non-flammability, crease resistance, and water repellency. After this process fabrics are in a form such that they may be used in manufacturing other products.

We have carefully considered these comments and have determined that the definition of "agricultural use" proposed in § 282.202(5) should be revised. Thus, the definition of "agricultural use" (§ 282.202(a) in the final regulations) has been revised to include, in addition to the "essential agricultural uses" set forth in 7 CFR 2900.3, the use of natural gas in textile operations to the extent it is used for the processing and finishing of natural fiber into a usable form. The revised regulations reflect the Commission's belief that the manufacture of end products should not be included as a stage of "natural fiber processing".

The regulations below and the exemption affidavit set forth the SIC codes applicable to the textile manufacturing operations which we have determined should be eligible for an interim agricultural use exemption from the incremental pricing program.

E. Interim Exemptions

As noted above, the exemptions herein described for small existing boilers and for agricultural users are, by the terms of the statute, "interim exemptions." Section 206 of the NGPA requires that no later than May 9, 1980, permanent exemptions with regard to these two categories of boiler fuel users be adopted by the Commission.

The permanent exemption for small boilers must be designed so that the entire class of boilers thereby exempted are those which were in existence on November 9, 1978, and whose total usage of natural gas as boiler fuel in 1977 represented only 5 percent of the total volume of natural gas transported by interstate pipelines and used in 1977 as boiler fuel.

The permanent exemption for agricultural use is not to be available to those agricultural users that the Commission determines have an alternative fuel or feedstock which is economically practicable or reasonably available.

It is self-evident that the regulations regarding permanent exemptions for small boilers and agricultural users may well alter the eligibility of users which may be able to obtain exemptions under the "interim rules". Thus, any user who obtains an exemption under the terms of the interim rules should not assume that the exemption will necessarily continue beyond May of 1980.

The Commission intends to begin its effort to implement the statutory provisions regarding the permanent exemptions in ample time to meet the May 9, 1980 statutory deadline.

F. Other Exemptions

In the June Notice, the Commission announced that it intended to issue within a few weeks a Notice of Proposed Rulemaking to deal with boilers of the size granted a statutory exemption from the incremental pricing program—300 Mcf usage per day or less—which have been constructed since the date of enactment of the NGPA. (By its terms, the statute grants an exemption only to those "small" boiler facilities which were in existence on the date of enactment.)

It also was announced in the June Notice that three dockets had been established to receive comments on the question of whether a rulemaking proceeding should be instituted to address three other classes of exemptions: (1) for so-called "load-balancing" facilities which burn oil as their alternative fuel; (2) for "load-balancing" facilities that burn coal as their alternative fuel; and (3) for entire states whose ratemaking practices accomplish the same goals as the incremental pricing program hereby established.

Many commenters urged that all of these exemption questions be answered as soon as possible, so that pipelines and distributors can determine exactly which customers will be subject to the regulations below, and so that pipelines can accurately predict the amount of surcharges their non-exempt customers will absorb and thus calculate the amount by which their PGA rates should be reduced.

We are sympathetic to the requests of pipelines that they be able to enter into the calculations required for the new "reduced PGA" approach with some degree of certainty. We will proceed as rapidly as possible on all outstanding questions, but believe that some estimating will be required by both pipelines and distribution companies.

As announced, we are issuing the Notice of Proposed Rulemaking in Docket No. RM79-48 with respect to new small boiler facilities. We will, as stated in that notice, hold a public hearing on the proposal as part of the public comment procedure and anticipate promulgating a final rule early in November. That final rule will, as is set forth in the Notice of Proposed Rulemaking, be subject to Congressional review.

We also are issuing notices in Docket Nos. RM79-45 and RM79-46 stating that rulemaking proceedings will not be instituted in either of those dockets. The rationale for our determinations in each are set forth in the respective notices.

Finally, by notices of August 22, 1979 (44 FR 50063, August 27, 1979) and September 10, 1979 (44 FR 53178, September 13, 1979), we extended the comment period in Docket No. RM79-47. As we have stated previously, we believe states cannot make informed comments on the question of state-wide exemptions until they know the details of the regulations adopted in this docket (RM79-14) and its companion, Docket No. RM79-21, both of which are issued today. A separate notice will be issued in the near future stating the date until which comments will be accepted in Docket No. RM79-47. We intend to move expeditiously on Docket No. RM79-47 once the period for receipt of comments has closed.

Many commenters urged that if all exemption questions could not be answered concurrently with adoption of regulations in Docket Nos. RM79-14 and RM79-21, provisions be included in the regulations in this docket (RM79-14) to permit interim exemptions. It was argued that such exemptions should be allowed until finalization of the Commission's position on outstanding exemption questions, provided the owner of the facility desiring the exemption filed a bond or undertaking in an amount established by the Commission to cover its liability should the facility ultimately be determined not to be eligible for an exemption.

We have given serious consideration to the concept of an interim exemption, but have determined not to incorporate such a procedure in the regulations hereby adopted. We believe an interim exemption procedure would create the potential for abuse and that high priority and exempt industrial users, as well as other non-exempt industrial users, might never be made whole if it were ultimately found that an interim exemption had been unjustifiably obtained.

As we have stated previously, any party may file for an adjustment of any of the regulations below under the procedures set forth in § 1.41 of the Commission's regulations in Title 18, Code of Federal Regulations. These regulations implement section 502(c) of the NGPA, as it relates to exceptions to certain NGPA regulations.

The Commission has the capability of processing § 1.41 petitions rapidly and believes that it will be able to handle any such petitions which arise due to the regulations below in an expeditious and equitable manner.

VII. Submetering

A. Proposed Treatment

The June 5th Notice described the background of the Commission proposal incorporated therein to require that volumes of natural gas used for exempt purposes within an industrial boiler fuel facility be measured by submeters in order not to be incrementally priced.

Under the proposed procedure, exempt volumes could be determined by submetering either exempt or nonexempt volumes, if the volume of exempt usage would thus be based on verifiable meter readings.

The submetering proposal was based on the following conclusions: that considerable in-plant submetering already is being done; that submeters can be purchased and installed at reasonable cost; and that the alternative of using estimates on a long-term basis, with verification of same performed by data verification committees, was not viable.

The June Notice also set forth the Commission's belief that end-users should own and bear the cost of submeters, since the end-users will benefit from submeters in that submeters will permit them to obtain an exemption from incremental pricing for a portion of their natural gas consumption. Further, the Commission concluded that ownership by end-users would maximize the tax benefits which would accrue from new installations of submeters.

As one aspect of its proposal, the Commission indicated that it might be necessary to rely on estimates in the short-term, in order to allow time for the installation of all submeters which would be required.

B. Comments Received

Considerable comment on submetering was received both at the June 27, 1979, hearing in this docket and in the written comments submitted in response to the Notice of Proposed Rulemaking.

Numerous commenters set forth the argument that submetering should not be mandated until the regulations implementing Phase II of the incremental pricing program are finalized, since those rules may obviate the need for many submeters which would be installed for Phase I purposes.

Further, several parties expressed serious concern whether the number of meters required could be obtained and installed by the proposed incremental pricing implementation date of January 1, 1980.

Several commenters argued that natural gas used for a non-boiler fuel purpose is exempt from incremental pricing by the terms of the statute itself. Therefore, these commenters argue, end-users should not have to bear any cost in order to receive the exemption from higher prices.

The cost and adminstrative burden which would be imposed on the natural gas industry and industrial consumers by a submetering requirement was discussed extensively. Several commenters provided statistical data and cost estimates for submetering in specific instances which indicate that on average, the unit cost per meter, including site preparation, related piping, etc., may be about $10,000, or twice the estimate set forth in the June Notice.

Further, it was generally claimed that the extent of in-place submetering is not nearly as widespread as envisioned in the Notice. Some commenters alleged that requiring installation of submeters will impair efforts to market natural gas and may induce some boiler fuel users to forego using natural gas (where such use is a small fraction of total use).

Some commenters argued that requiring submeters (paid for by the users) would raise the cost of gas above alternate fuel costs. Commenters also stated that in some instances it is physically and/or economically impractical to install submeters, due to the configuration of the particular industrial facilities in question. Where by-product gases from other processes are mixed with natural gas in order to fuel a boiler, it was argued that it would be most difficult, if not impossible, to install a submeter which could measure the volume of natural gas thus being used.

Also, commenters argued that in the instances where the boiler output (steam and/or electricity) is used for both exempt (such as agricultural) and non-exempt purposes, submetering would be useless because other techniques must be employed to determine the exact exempt and non-exempt volumes.

Further comment was offered to the effect that even if submeters already exist, or are subsequently installed, it does not follow axiomatically that such meters are suitable for billing purposes.

The customer and the supplier might have differing requirements on such factors as pressure, temperature and Btu corrections. Other problems which were noted included the problems attendant to regular verification of the meter, which party would be responsible for reading and upkeep of the meter, etc. A number of commenters opposed our tentative decision that end-users should bear the cost of submetering.

Many of the commenters who opposed a mandatory submetering requirement proposed in the alternative that exempt or non-exempt volumes be determined and attested to by qualified engineers on a monthly basis, or that such volumes be determined by agreement between the supplier and the purchaser. Those commenters which urged the use of estimates argued for certified submissions rather than the formerly advocated use of data verification committees. Some commenters suggested that curtailment case data be used to determine the volumes of exempt and non-exempt purchases.

A few commenters believed that the proposal raised a "Catch 22" problem with respect to small boilers. These commenters interpreted the regulations to require installation of a submeter in order to obtain an "under 300 Mcf per day" exemption. Commenters noted that once the low usage was established, however, the submeter would no longer be needed, since the facility would be exempt from the program.

C. Treatment Adopted

Based on our current knowledge regarding submetering, the Commission believes the approach of requiring installation of submeters is the only one available to insure implementation of the program in the manner which was envisioned by the Congress.

We are persuaded, however, that it is appropriate to extend the submetering requirement until such time as the scope of the Phase II regulations of the incremental pricing program is established. We cannot now speculate on whether the yet-to-be written section 202 rule will reduce the need for submetering. That rule may even expand the need for submeters.

The Phase II regulations, required by section 202 of the NGPA, must be submitted to the Congress for its review. By the statute, the Congress must be allowed 30 days for review, which is to be 30 days of continuous session as defined in the statute. In order to allow ample time for 30 days of continuous session following May 9, 1980, and to allow for a period of time for the purpose described below following that date, we have determined to require installation of submeters by November 1, 1980, unless the Phase II regulations make alteration of that requirement appropriate.

If Congress should disapprove the Phase II regulations which the Commission must promulgate, boiler fuel users would have a period of at least 30 days, based on our calculations, in which to install needed submeters. As set forth in the regulations below, a purchase order for the required submeters would satisfy the November 1, 1980 installation requirement.

Therefore, the regulations below permit the use of estimates and/or supplier-customer agreements until November 1, 1980. Absent the installation of operational submeters by November 1, 1980, or the acquisition of a purchase order for submeters by that date, all volumes sold to a non-exempt industrial boiler fuel facility on or after November 1, 1980, will be deemed subject to incremental pricing.

We accept that the estimate on the cost of a submeter which was included in the June 5th Notice may not have been illustrative of most situations and therefore may have been lower than what the cost generally will be. However, even accepting an estimate twice that of ours, and not taking into account the offsetting tax benefits, the payback term for such installations would be only about 100 days for a customer which thereby received a 10 cents per Mcf reduction in the cost of gas for exempt uses of approximately 1000 Mcf per day.

The generally short payback times which reasonably may be expected, and the advantage of having exempt and non-exempt volumes determined on a uniform basis to the greatest extent possible, in our opinion justify the requirement for installation of submeters.

We believe that the capital cost of submeter installations should be borne by the consumer, since submetering will serve to quantify the exempt volumes entitled to lower rates. We have not addressed the question of who should actually own the submeter, and thus leave this question to the consumer and supplier, or the regulatory body which has jurisdiction. We further believe that submeter installations should be subject to the natural gas supplier's accuracy and safety standards, security control and access as needed for reading and maintenance. To do otherwise would create the potential for undue discrimination against other consumers. However, none of the Commission's views on these questions have been included as mandatory requirements in the regulations. These questions are thus left to suppliers and customers to resolve as is appropriate and workable.

This Commission has determined that the long-term use of estimates would not be a viable regulatory approach for establishing volumes of gas used for non-exempt purposes. The primary weakness in the use of estimates is that a strong motivation would exist to estimate low for non-exempt consumption (and therefore high for exempt consumption). It is equally apparent that a multiplicity of estimating techniques would be employed, reflecting both the preferences of numerous individual estimators and a wide variety of individual fact situations.

Similarly, suppliers and their customers could be strongly motivated to agree to low non-exempt volume figures, since by so doing costs that otherwise would be borne by non-exempt sales would be shifted to others, including customers of other distributors and other pipelines, and in other states.

Further, we foresee a large verification burden if either the engineering estimate or the seller-buyer agreement approach were adopted on a long-term basis. By requiring the installation of submeters, we believe questions of motivation will be largely avoided and verification burdens will be minimized.

The use of curtailment case data to determine exempt/non-exempt breakdowns would not be appropriate. In most instances, such data reflect past base period conditions and in our opinion should not be used as a basis for current billings.

As stated above, estimates or supplier/customer agreements will be utilized for the period January 1, 1980 through October 31, 1980. The regulations below provide that as of November 1, 1980, all volumes claimed to be used for exempt purposes must be based on appropriate submeter readings. We believe that even in those situations where a mixed stream is fed into a boiler, or where the output of a boiler is used for both non-exempt and exempt purposes, the installation of submeters would aid in arriving at a more accurate estimation of the non-exempt usage. We therefore encourage installation of submeters at strategic points which would allow for closer estimates than otherwise could be obtained. This aspect of the submetering problem will be discussed, however, in detail at the technical conference to be held in early November, as described below.

Those commenters which suggested a "Catch 22" problem with respect to small boilers perceived a problem which does not exist. The proposed regulations, and final regulations below, provide for the "under 300 Mcf" exemption on the basis of attestations for 1977.

D. Technical Conference

The above described approach for quantifying volumes which are consumed for boiler fuel in conjunction with volumes which qualify for exemption from the incremental pricing program represents the determination this Commission has reached following consideration of the entire record developed in this docket.

However, we are seriously concerned by several of the arguments which have been voiced in opposition to a mandatory submetering requirement. In particular, we are concerned about imposing a disproportionately large cost on industrial end-users which would serve no purpose other than to meet the requirements of this program. We are also seriously concerned about those situations as to which it has been alleged submeters could not provide an indication of the volume of natural gas actually consumed as non-exempt boiler fuel.

The regulations set forth below will permit the use of estimates or supplier/customer agreements in order to calculate non-exempt usage for the period January 1, 1980 up until the required installation date of November 1, 1980. We believe it would be useful for all concerned parties and for this Commission to develop standardized methods by which such estimates will be made. It is our intention to issue guidelines on such standardized procedures prior to the date on which the first set of estimates will have to be made under the regulations below.

In order to aid us in the development of these guidelines, we will hold a technical conference on the topic of submeters. Further, if the information submitted at this conference should indicate that revisions should be made to our submetering requirement, we will propose to amend the regulations hereby adopted in an appropriate manner.

The technical conference will be held in Chicago, Illinois in early November. The exact date, time and location of the conference will be announced in the near future. The Commission technical staff will chair a panel, and it is hoped that a round-table discussion format can be used.

It is our hope that technical personnel representing industrial end-users will attend the conference and offer as much detailed information as possible to Commission staff on the many aspects of submetering which have been raised thus far in this proceeding. Additionally, we request detailed recommendations concerning the use of estimates for quantifying exempt and non-exempt volumes, in particular as to how such estimates could be standardized and verified. We also intend to invite representatives of meter manufacturing firms to attend this conference.

Natural gas suppliers which are included in the incremental pricing program are hereby requested to assist the Commission in the compilation of a list of industrial users and manufacturers of meters who should be invited to this technical conference. The Commission will send invitations to as many industrial end-users of natural gas and meter manufacturing firms as it is able to identify, and thus requests assistance in the identification effort.

The invitations which will be sent will specifically request that those representatives of end-users who attend the conference be persons who are familiar with day-to-day plant operations and who can offer comments based on actual experience as to the advantages and disadvantages, and attendant difficulties of installing submeters in industrial facilities.

Finally, the Commission hereby wishes to make clear its intention, should this technical conference result in the acquisition of no further information than it has at present on the subject of submeters, and should the Phase II regulations not obviate the need for submeters, to proceed with allowing the submetering requirement incorporated in the regulations below to become fully effective on November 1, 1980.

VIII. Direct Sales

The proposed regulations set forth in the June 5th Notice provided that the MSAC of an industrial user served directly by an interstate pipeline would be calculated as the difference between the contract price the user was paying and the alternative fuel price ceiling applicable to the facility. The Notice also, however, set forth five alternative formulas for the calculation of the MSAC of a direct sale customer of an interstate pipeline.

The Commission stated that it was soliciting comment on the question and the six alternatives proposed, and that it had not made a preliminary determination as to which approach was appropriate or whether there existed any jurisdictional questions with respect to any of the alternatives.

Many comments were submitted on this question. Pipeline companies that have direct sale non-exempt industrial customers argued that the Commission's regulations cannot utilize anything other than the contract rate for the calculation of surcharges as to such users. These commenters argued that incorporation of any of the five alternative formulas into the regulations would result in *de facto* rate setting, a function outside the ambit of Commission authority.

Commenters who opposed the choice of contract prices for MSAC calculations argued that the question is not one of rate-setting. These commenters argue that the Commission is required to prescribe a method whereby incremental gas costs will be passed through to industrial users who are served directly by interstate pipelines. These commenters assert that if the Commission were to adopt the "contract price" approach, incremental gas costs would *not* be passed through to direct sale customers. Rather, these commenters allege that interstate pipelines would simply increase their contract prices to the applicable alternative fuel price ceilings, and any increase that would otherwise have represented an incremental pricing surcharge would then represent profit to the pipeline.

In such a scenario, incremental gas costs would first be passed through to industrial customers of sale-for-resale customers of the pipeline, and then to all customers when the non-exempt industrial customers could no longer absorb surcharges. This would result in exempt customers ultimately bearing costs which Congress intended should be borne by industrial users.

The Commission has given very serious consideration to this question. The Commission's deliberation has resulted in a determination that it has the authority to insure the passthrough of incremental gas costs to direct customers of interstate pipelines.

The Commission gives great weight to two provisions of Title II and believes such provisions make clear that Congress intended the Commission have authority to take such action as is necessary in order to insure that the full intent of Title II is carried out.

Section 204(c)(2)(B), as well as other provisions, states that surcharges are to be passed through to direct as well as indirect industrial customers:

> (2) SURCHARGE PASSTHROUGH.—The rule required under section 201 (including any amendment under section 202) shall provide
>
> * * * * *
>
> (B) one or more methods for imposing such surcharge on the rates and charges of such pipeline applicable to any volume of natural gas delivered, during the calendar period involved, for industrial use to any incrementally priced industrial facilities served directly by such interstate pipeline and to incrementally priced industrial facilities served indirectly through any other interstate pipeline or any local distribution company.

In addition, Section 204(c)(2)(D) states as follows:

> (D) EXCEPTION.—The methods prescribed under subparagraphs (B) and (C) need not require—
>
> (i) elimination or reduction under subparagraph (B) of the surcharge with respect to any specific deliveries of natural gas; or
>
> (ii) the increase under subparagraph (C) of the surcharge generally applicable due to any adjustment under subparagraph (B), if the Commission determines that to do so would be impracticable or unnecessary to carry out the purposes of this title.

The Commission interprets section 204(c)(2)(D) to place in it the authority to take whatever action may be necessary, including not to permit a reduction in the surcharge to a particular industrial facility, in order to "carry out the purposes" of Title II.

The Commission thus believes that the statute does not state that the surcharge must always be reduced in order to bring the price of gas down to the alternative fuel price ceiling with respect to a particular user. The Commission takes this view because it believes that in a situation where the Commission determines that a surcharge of a certain magnitude should continue to be passed through to an industrial user, it would be within the power of the customer not to agree to a higher contract price.

The Commission agrees in theory with the comments which argued that Title II simply requires an alteration of the Commission's traditional cost-allocation methods between jurisdictional and non-jurisdictional customers. Pursuant to Title II, gas cost acquisition costs can no longer be allocated on a strictly volumetric basis. Title II significantly amends the manner in which gas acquisition costs are to be allocated, and requires that certain portions of those costs be allocated to industrial customers not exempted from the program, regardless of whether those customers are served by the pipeline indirectly through local distribution companies, or served directly by the pipeline itself.

The Commission's deliberation on the direct sales question has resulted in a determination to adopt the regulations which were proposed with respect to this area. Thus, the Commission envisions that the MSAC of a non-exempt industrial customer served by an interstate pipeline will be calculated as the difference between the contract price which has been negotiated by the customer and the pipeline and the alternative fuel price ceiling (with appropriate adjustments for taxes) applicable to the customer's facility.

The Commission has chosen this approach for several reasons. First, we have insufficient data on the direct sales market—due to the fact that this Commission did not have rate-setting jurisdiction with respect thereto under the Natural Gas Act—to allow us to conclude whether the potential for circumvention of the intent of Title II is real or merely theoretical. If real, we also lack data on the extent of the potential and thus whether the problem warrants adoption of a regulatory solution.

If a solution is warranted, the record in this proceeding clearly indicates that further information and discussion is needed before a regulation could be promulgated which would be both administerable and equitable.

However, we intend to monitor the activity in the direct sales market over the next several months, and if it is found that contracts are being negotiated in an abnormal manner in order to eliminate potential surcharge absorption capability, the Commission may take action to prevent such a circumvention of the intent of Title II.

The Commission is also looking into whether a potential such as that described with regard to direct sale customers of interstate pipelines exists with respect to industrial customers of some local distribution companies. If such a situation should be found, the Commission will consider taking appropriate action with regard thereto.

IX. Scope of the Regulations

A. Definitions

Some commenters suggested that the definition of "industrial facility" which was proposed in the June 5th Notice was not broad enough to include all operations which are commonly considered to be industrial in nature. The definition proposed would have included only "any facility which primarily changes raw or unfinished materials into another form or product." It was noted that this definition would not include facilities engaging in extraction or processing activities which do not necessarily result in another "form" or a different "product."

We agree that our proposed definition was not sufficiently broad. Therefore, we have adopted the following definition of "industrial facility" for

inclusion in § 282.103 of the regulations below:

> **"Industrial facility" means any facility engaged primarily in the extraction or processing of raw materials, or in the processing or changing of raw or unfinished materials into another form or product.**

Several commenters also raised queries about the exact definition of a "facility". The NGPA does not set forth a definition of the term, nor did the proposed regulations endeavor to define the term. We believe, however, that it would be useful to include a definition of this concept so as to correct any confusion or misunderstanding that a single boiler could qualify as a facility. We believe a definition of "facility" will be especially helpful for the application of the rule proposed in Docket No. RM79-48 with respect to small boilers constructed since the date of enactment of the NGPA.

Therefore, we have included in § 282.103 of the regulations below a definition of facility as follows:

> **"Facility" means all buildings and equipment located at the same geographic site which are commonly considered to be part of one plant, mill, refinery, or other industrial complex.**

B. Exempt End-Uses

Several commenters discussed the point that Title II is drafted in a somewhat confusing manner with respect to its coverage and the exemptions granted thereto. Specifically, the provisions of Title II are only to apply to "boiler fuel use of natural gas by any industrial boiler fuel facility." The statute goes on, however, to set forth specific exemptions from the requirements of the statute for "any school, hospital, or other similar institution"—facilities which are not commonly thought of as industrial and thus would be outside the scope of the statutory provisions without the specific grant of an exemption.

Because the somewhat inconsistent treatment in the statute leads to a certain amount of confusion, several commenters urged us to set forth specifically that the regulations for the incremental pricing program are not applicable to the use of natural gas in facilities which are not industrial facilities.

We agree that the statutory structure can lead to confusion and that it would be helpful to clarify that the regulations below do not apply to the use of natural gas for uses other than boiler fuel use by industrial facilities. Thus, we have revised § 282.203 of the regulations below to include a provision stating that the incremental pricing regulations apply only to industrial facilities which use natural gas as a boiler fuel.

C. Ignition Fuel and Flame Stabilization

Several commenters raised the question of whether gas consumed in boilers for ignition fuel and flame stabilization (IF&FS) purposes should be treated as boiler fuel under incremental pricing. The comments noted the pendency of IF&FS issues in other proceedings (e.g., El Paso Natural Gas Co., Docket No. RP76-2 (Ignition Fuel and Flame Stabilization)). The basic issues in those proceedings, however, differ from the issue here. Those proceedings are concerned mainly with whether such usage should be accorded high priority (process use) status, and with alternate fuel capability and conversion costs for curtailment purposes.

In those proceedings, it is argued that IF gas is used for one of three purposes: to achieve initial combustion of another fuel in pilot ignitions; to warm up the boiler to enable safe and complete ignition of a less volatile primary fuel (usually oil or coal); and to maintain temperature in non-base load units.[4] The first two uses are intermittent; the third is longer term, but it is not needed after firing by another fuel commences.

FS gas, by contrast, is used to avoid flameouts resulting from momentary breaks in the supply of another fuel, which can pose operational and safety problems. The use of gas for flame stabilization is a continuous use during boiler operation.[5]

The record in Docket No. RP72-6 (IF&FS) reveals generally that IF gas

consumption is small by comparison to FS consumption. The latter, however, often is a significant fraction—25 percent or more—of total gas consumption.[8] The same record reveals that IF&FS gas was used by approximately 130 customers served directly and indirectly by El Paso Natural Gas Company. The preponderance of volume, however, was used in electric utility boilers.

We believe that regardless of our eventual resolution of the curtailment case issues, IF&FS gas should not be summarily exempted from incremental pricing when burned in industrial boiler fuel facilities in quantities, by persons, and for purposes which are not statutorily exempt. To treat IF&FS gas otherwise would lead us to similarly exempt warmup, temperature maintenance and pilot fuel in straight, natural gas fired boilers as well. Such a result would, we believe, be contrary to the letter and spirit of the statute. Furthermore, since FS gas contributes meaningfully to the total energy input to operating boilers, it should be regarded as boiler fuel.

Our conclusion with respect to these two uses of natural gas is, of course, a generalized one. Any user who believes that his situation merits special consideration may file a request for an adjustment to these regulations pursuant to § 1.41 of the Commission's regulations.

X. Refunds

One commenter noted that the proposed regulations did not address the question of how jurisdictional refunds attributable to periods prior to January 1, 1980, but which had not been paid as of that date, should be treated. The comment further noted that it appeared that non-exempt customers would not receive any benefit from such refunds under the "reduced PGA" approach.

This result would occur because non-exempt customers, according to the majority of data provided to us, will be priced at the applicable alternative fuel price ceiling for their use of natural gas from the inception and throughout Phase I of the program. If refund payments were simply used to reduce the 191 account (as has been done in the past) the PGA rate applicable to all customers would be reduced. Non-exempt customers, however, would then simply bear a larger surcharge and effectively not receive the benefit of the refund.

The Commission has determined that such a result would be inequitable to non-exempt customers and that, in contrast, non-exempt customers should receive the full amount of refunds to which they are entitled with respect to gas service purchased prior to implementation of the incremental pricing program.

Therefore, the Commission has included a provision in the regulations below to deal with the jurisdictional portion of refunds applicable to the period prior to January 1, 1980, which are ultimately determined to be payable for sales to non-exempt industrial users. One possible regulatory solution would have been to revise the formulas to be used for the calculation of MSAC's. This approach, however, would have resulted in further complexity in a formula which is already highly technical. Moreover, we believe the problem of refunds will be of limited duration and it would thus be inapproriate to solve the problem by amending regulations which will have a longer applicability.

Therefore, it appears that a separate regulatory provision to address this problem is most appropriate. Accordingly, a new § 282.506 is included in the regulations herby adopted. This regulation requires that the jurisdictional portion of refunds applicable to non-exempt industrial facilities determined after December 31, 1979, to be applicable to periods prior to January 1, 1980, plus the interest applicable thereto, shall be paid in a lump-sum payment to the suppliers of the non-exempt facilities on the dates prescribed by the Commission orders which require the refunds.

The lump-sum payments are to be made to the sale for resale customers for the benefit of their non-exempt customers to whom the sales for which refunds are ordered were made. The amounts of the refunds thus payable will be calculated on the basis of the sales made to the non-exempt customers during the period when the supplier rates which give rise to the refund were in effect.

The treatment of the jurisdictional portion of all refunds applicable to periods after January 1, 1980, will be governed by section 154.38(d)(4)(vii) of the Commission's regulations.

XI. Filing Requirements

The proposed regulations contained a provision to require the filing of informational tariff sheets which would reflect the incremental pricing surcharges projected for non-exempt customers and used in calculating "reduced PGA" rates. The final regulations below incorporate this filing as a mandatory requirement (not limited to informational purposes) in § 282.602(a)(1)(ii). These filings will permit commission staff to audit billings which are calculated in accord with the optional billing procedure for pipelines described in section IV. B. above.

Several commenters objected to the provision set forth in proposed § 282.602(d)(2) which would require the filing of information as to each source of supply by API well identification number. The Commission recognizes that such a requirement will result in the filing of significantly more detailed information than is filed at present. However, the Commission believes that only this information will enable staff to audit the incremental gas costs which are used in calculating "reduced PGA's". Staff anticipates performing spot audits of the revised tariff sheets.

Pipelines are hereby informed that no specific format is prescribed for the submission of this well-by-well information, and that submission of a copy of a company's computer print-out with this information will satisfy this requirement.

Further, one change has been made to the regulations as proposed in that the well-by-well information is only required to be submitted if it is available. The Commission believes that this information is in fact in most instances kept as a matter of course.

XII. Environmental Issues

A few commenters continue to urge that a complete Environmental Impact Statement should be prepared with respect to these regulations. As stated in our June 5th Notice, an Environmental Assessment of these regulations was prepared and the conclusion was reached therein that the proposed regulations would not be a major Federal action significantly affecting the quality of the human environment.

None of the comments submitted in response to the June 5th Notice have led us to conclude that our original position on this issue warrants further consideration or a change in our original conclusion. Thus, an Environmental Impact Statement with respect to these regulations will not be prepared.

XIII. Special Circumstances

We have noted several times in this preamble and in its companion document in Docket No. RM79-21 that § 1.41 of the Commission's regulations provides procedures whereby individual parties may request an adjustment to the regulations below if it is believed these regulations will result in special hardship, inequity, or an unfair distribution of burdens.

We also note the recent adoption by the Commission of interim regulations which provide procedures whereby individual parties may seek an interpretation of the NGPA or any rule or order issued thereunder. These regulations appear at 18 CFR 1.42, and were issued on August 7, 1979 in Docket No. RM79-65 (44 FR 48171, August 17, 1979). Under these regulations, an interpretation will be issued only if the action which forms the basis for the request is completed or is likely to occur. Interpretations will generally not have precedential value and will be issued by the General Counsel of the Commission.

XIV. Effective Date

In the June 5th Notice we proposed that the incremental pricing regulations included in Docket Nos. RM79–14 and RM79–21 would become effective September 1, 1979. We have determined, however, to make the regulations effective as of November 1, 1979. The regulations still require that incremental gas costs begin to be booked in by natural gas suppliers as of January 1, 1980, and that incremental surcharges commence being billed for usage during the month of January, 1980.

The effective date of the incremental pricing regulations governs the date on which the price of certain categories of high-cost natural gas will be decontrolled, as set forth in section 121(b) of the NGPA. Further, section 201(a) of the NGPA prescribes that regulations to implement Title II must be made effective no later than 12 months following enactment of the NGPA, i.e., November 9, 1979. We believe it is consistent with the scheme envisioned in the statute for establishment of the incremental pricing program and the decontrol of certain types of high-cost natural gas to make the regulations below effective as of the first day of the month in which the mandatory effective date falls.

The sections of the regulations below governing the obtaining of exemptions, sections 282.201 through 282.206, are being treated in a manner different than the majority of the regulations and are being made effective October 15, 1979. It is necessary that exemption affidavits be mailed out by natural gas suppliers to their customers by that date in order that the "reduced PGA" rate can be calculated by December 1, 1979. As required by section 553(d) of Title V of the United States Code, the Commission thus finds that good cause exists to make these six sections of the regulations below effective October 15, 1979, less than 30 days subsequent to publication of the regulations.

XV. Time Line

In our June 5th Notice, we included a summary time line of the events which would take place under the regulations in this docket and its companion, Docket No. RM79–21. A number of comments were submitted on various aspects of the time line and the suggestion made that more details should be included therein. Obviously, also, the new effective date for the regulations requires a significant revision of the time line which was proposed.

Set forth below are two separate time lines which we believe will be of aid to all parties in implementing these regulations in the most timely manner possible.

The first time-line is similar to that included in the June 5th Notice; it sets forth the major steps which must take place under the regulations. The second time-line describes the steps which must take place on a monthly basis in order to arrive at monthly surcharges pursuant to § 282.504 of the regulations.

A. Time Line for Implementation of Program

October 3, 1979—Exemption affidavits and alternative fuel price ceiling affidavits available through the Office of Public Information.

October 15, 1979—Sections 282.201–282.206 of the regulations become effective. Natural gas suppliers mail exemption affidavits to all industrial boiler fuel facilities which were not determined to be exempt from an examination of the natural gas supplier's own records.

November 1, 1979—Major portion of regulations become effective. In accordance with the natural gas suppliers' requests as contained in the suppliers' mailings of October 15, exemption affidavits are returned to natural gas suppliers by industrial boiler fuel facilities claiming an exemption in whole or in part.

November 1, 1979—Interstate pipelines file revised PGA provisions and incremental pricing surcharge provisions; pipelines and local distribution companies determine projected MSAC's.

November 15, 1979—Local distribution companies notify supplying pipelines of their projected MSAC's for the period commencing January 1, 1980.

November 30, 1979—Interstate pipelines file reduced PGA tariff sheets and estimated incremental pricing surcharge tariff sheets for the period commencing January 1, 1980.

December 20, 1979—Incremental pricing ceilings for January, 1980 are published.

January 1, 1980—Effective date of tariff sheet filed November 30, 1979. Incremental gas acquisition costs begin to be booked by natural gas suppliers.

January 15, 1980—Natural gas suppliers file lists of non-exempt industrial boiler fuel facilities with the Federal Energy Regulatory Commission and with state or local commissions having jurisdiction.

January 2, 1981—Natural gas suppliers review customer lists and list of non-exempt industrial boiler fuel facilities filed on January 15, 1980 to determine which facilities should be included on January 15, 1981 list.

January 15, 1981—Natural gas suppliers file updated lists of non-exempt industrial boiler fuel facilities with the Commission and with state or local commissions having jurisdiction.

B. Surcharge Billing Time Line

This time line assumes that needed information will be communicated by distributors to supplying pipelines and between pipelines by telephone, and that such information will later be confirmed in writing. In the outline, Months A, B, C and D are any four consecutive calendar months.

The time sequence set forth in items 1–14 does not reflect the additional time which will be available to pipeline and distribution companies if they choose to follow the two optional billing procedures included in the regulations. Items 15 and 16 *do* reflect the optional billing procedures.

1. Distributors read meters of non-exempts from the 21st day of Month B to the 31st day of Month B.

2. Distributors calculate MSAC for each non-exempt customer based on:

(a) Month B rates,

(b) Month B alternative fuel price ceilings published on the 20th of Month A, and

(c) consumption based on meter readings taken from the 21st to 31st day of Month B.

3. Distributor totals MSAC's of all non-exempt customers.

4. Distributor allocates MSAC between suppliers based on the Month B purchase volumes.

5. Distributor notifies supplier of Month B MSAC on or about the 4th of Month C.

6. Pipelines with direct sales will follow the same reading and MSAC calculation procedures listed in items Nos. 1 to 4.

7. Pipeline totals MSAC on its system for Month B.

8. Pipeline allocates the Month B MSAC between suppliers based on Month B purchase and production volumes.

9. Pipeline notifies its suppliers of their share of the Month B MSAC about the 6th of Month C.

10. Subsequent pipeline to pipeline upstream movement of data should take one day.

11. The most upstream pipeline totals all the MSAC on its system for Month B.

12. The most upstream pipeline compares this total MSAC for Month B to its total incremental costs for Month B.

13. The most upstream pipeline notifies its customers of the amount of surcharge each will be billed for Month B (based on the lesser of MSAC or incremental costs determined in #12).

14. This notification continues from pipeline to pipeline down to the most downstream pipeline. This information must reach the most downstream pipeline on or about the 8th of Month C in time for the regular Month B bill on or about the 10th of Month C.

15. On or about the 10th of Month C:

(a) *Pipelines may either:*

(1) render their regular bills for Month B along with the actual surcharge applicable to Month B; or

(2) in the case of sale-for-resale transactions, render their regular bills for Month B along with a surcharge which consists of the net of:

(i) the projected incremental surcharge for Month B which was filed with the Commission and which was used in determining the "reduced PGA", and

(ii) the net difference between:

(A) the projected surcharge billed for Month A, and

(B) the actual surcharge payable, as computed in accordance with the regulations, for Month A.

(b) *Distributors may either:*

(1) render their regular bills for Month B along with the actual surcharge applicable to Month B; or

(2) render their regular bills for Month B, along with a surcharge which consists of the net of:

(i) the alternative fuel price ceiling, plus applicable taxes, applicable to the facility for Month B, and

(ii) the net difference between:

(A) the alternative fuel price ceiling, plus taxes, billed, and

(B) the actual surcharge payable, as computed in accordance with the regulations, for Month A.

16. On or about the 10th of Month D:

(a) Pipelines will render their next bills, computed in the manner prescribed above, and if they billed in the optional manner for sale-for-resale customers, they will net the difference between the estimated surcharge billed in Month C and the actual surcharge that should have been billed in Month C for Month B's consumption. This over or under amount billed in Month C will then be netted against the estimated surcharge billed in Month D.

(b) Distributors will render their next bills, computed in the manner prescribed above, and if they billed in the optional manner, they will net the difference between the alternative fuel price ceiling, plus taxes, billed in Month C and the actual surcharge that should have been billed in Month C for Month B's consumption. This over amount billed in Month C will then be netted against the alternative fuel price ceiling, plus taxes, billed on Month D.

(Natural Gas Act as amended, 15 U.S.C. 17 *et seq.*; the Natural Gas Policy Act of 1978, Pub. L. 95–621, 92 Stat. 3350, 15 U.S.C. 3301, *et seq.*; the Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.*; E.O. 12009, 42 FR 46267.)

In consideration of the foregoing, Title 18 of the Code of Federal Regulations is amended by revisions in Parts 154, 201, 204 and by the addition of a new Part 282, to read, in part, as set forth below.

By Direction of the Commission.

Lois D. Cashell,
Acting Secretary.

Appendix A

[Note.—This appendix will not appear in the Code of Federal Regulations.]

Federal Energy Regulatory Commission, Washington, D.C. 20426.

Exemptions From Incremental Pricing for Certain Categories of Industrial Boiler Fuel Use of Natural Gas.

Docket No. RM79–14.

Participation is Voluntary.

Copies of executed exemption affidavits filed with the Commission shall be available through the Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426.

Please Read Before Completing This Affidavit.

Purpose

The Natural Gas Policy Act of 1978 (NGPA) provides that natural gas used as boiler fuel by any industrial boiler fuel facility will be subject to incremental pricing surcharges unless exempted. The statute provides for certain exemptions from these incremental pricing surcharges. To be wholly or partially exempt from incremental pricing surcharges the boiler fuel must be consumed for one of the statutorily exempt uses. This affadivit serves the purpose of identifying those natural gas uses within your facility which are entitled to a full or partial statutory exemption from incremental pricing surcharges but which could not be identified as exempt through review of the records of your natural gas supplier.

* * * * *

NOTICE

* * * * *

If you do not complete and return this affidavit setting forth your claim to a total or partial exemption, *ALL* gas sold to your facility will be subject to incremental pricing surcharges. Additionally, if circumstances or ownership change, you should immediately notify your natural gas supplier(s) of the change so that the correct amount of surcharge may be calculated as to your gas use or, if needed, you can complete a new exemption affidavit to obtain a new or changed exemption from the incremental pricing program. Failure to report changes can subject your facility to civil and criminal penalties under Section 504 of the Natural Gas Policy Act of 1978.

GENERAL INSTRUCTIONS

If you claim an exemption from incremental pricing surcharges for all, or a portion, of the gas used by your facility which has been identified by your natural gas supplier as a potentially non-exempt industrial boiler fuel facility, this affidavit should be completed and signed, under oath, by a responsible official associated with the facility. A separate affidavit must be filed for each facility for which a total or partial exemption from incremental pricing surcharges is claimed.

The original and five copies of this affidavit should be submitted to:

Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

Also, one copy must be submitted to your natural gas supplier. Additionally, each industrial facility must retain such records, documents and data which formed the basis for the exemption claimed on this affidavit. Definitions which may be helpful in completing this affidavit are provided below.

If you have any questions concerning this affidavit contact Ms. Alice Fernandez on (202) 275–4406.

DEFINITIONS

(1) "Natural gas supplier" means an interstate pipeline or a local distribution company.

(2) "Local distribution company" means any person other than an interstate pipeline that receives gas directly or indirectly from an interstate pipeline and which is engaged in the sale of natural gas for resale or for ultimate consumption. A person is not considered as having received gas directly or indirectly from an interstate pipeline if the only service performed by an interstate pipeline for the purchaser is a transportation service.

(3) "Boiler fuel use" means the use of any fuel for the generation of steam or electricity.

(4) "Facility" means all buildings and equipment located at the same geographic site which are commonly considered to be part of one plant, mill, refinery, or other industrial complex.

(5) "Industrial facility" means any facility engaged primarily in the extraction or processing of raw materials, or in the processing or changing of raw or unfinished materials into another form or product.

(6) "Industrial boiler fuel facility" means any industrial facility which uses natural gas as a boiler fuel.

(7) "Non-exempt industrial boiler fuel facility" means any industrial boiler fuel facility other than any such facility which has been exempted from the incremental pricing program in accordance with Part 282 of the Commission's rules and regulations.

(8) "Agricultural use" means any use of natural gas (a) which is certified by the Secretary of Agriculture under 7 CFR 2900.3 as an "essential agricultural use" pursuant to section 401(c) of the NGPA; or (b) which is used in the following textile manufacturing operations, limited as set forth below to the production or processing of natural fiber, as set forth in the *Standard Industrial Classification Manual—1972:*

Industry Sic No. and Industry Description—.

220—Broad Woven Fabric Mills, Cotton.
222—Broad Woven Fabric Mills, Man-made Fiber and Silk (natural fiber processing only).
223—Broad Woven Fabric Mills, Wool (Including Dyeing and Finishing).
224—Narrow Fabrics and Other Smallwares Mills: Cotton, Wool, Silk, and Man-made Fiber (natural fiber processing only).
2257—Circular Knit Fabric Mills (natural fiber processing only).
2258—Warp Knit Fabric Mills (natural fiber processing only).
226—Dyeing and Finishing Textiles, Except Wool Fabrics and Knit Goods (natural fiber processing only).
228—Yarn and Thread Mills (natural fiber processing only).
2291—Felt Goods, Except Woven Felts and Hats (natural fiber processing only).
2293—Paddings and Upholstery Filling (natural fiber processing only).
2294—Processed Waste and Recovered Fibers and Flock (natural fiber processing only).
2295—Coated Fabric, Not Rubberized (natural fiber processing only).
2297—Nonwoven Fabrics (natural fiber processing only).
2299—Textile Goods, Not Elsewhere Classified (natural fiber processing only).

(9) "School" means a facility the primary function of which is the delivery of instruction to regularly enrolled students in attendance at such facility. Facilities used for both educational and non-educational activities are not included under this definition unless the latter activities are

merely incidental to the delivery of instruction.

(10) "Hospital" means a facility the primary function of which is the delivery of medical care to patients who remain at the facility. Outpatient clinics or doctor's offices are not included in this definition. Nursing homes and convalescent homes are included in this definition.

(11) "Similar institution" means a facility the primary function of which is the same as the primary function of the facility to which it is compared.

(12) "Qualifying cogeneration facility" means a cogeneration facility which meets the requirements prescribed by the Commission pursuant to section 201 of the Public Utility Regulatory Policies Act of 1978.

—Footnotes—

[1] *Regulations Implementing Alternative Fuel Cost Ceilings on Incremental Pricing Under the Natural Gas Policy Act of 1978.* Docket No. RM79-21. Final Rule issued on September 28, 1979. *See also* in Docket No. RM79-21, *Rule Exempting Industrial Boiler Fuel Facilities from Incremental Pricing Above the Price of No. 6 Fuel Oil,* issued on September 28, 1979.

[2] H.R. Rep. No. 95-1752, 95th Cong., 2d Sess. 96 (1978).

[3] *See, e.g.,* H.R. Rep. No. 95-1752, 95th Cong., 2d Sess. 102-103, 112-113 (1978); 124 *Cong. Rec.* S14,957 (daily ed. Sept. 12, 1978) (remarks of Sen. Talmadge).

[4] See: Administrative Law Judge's September 15, 1978, Initial Decision, mimeo pp. 15-16.

[5] *Supra.*

[6] Exhibit No. 27; the consumption of other fuels is not shown.

1.0 Name of Company or Organization: ____________________

____

2.0 Name of Facility: ____________________

* * *

3.0 Address: ____________________
Number Street

____
City/Town County State Zip Code

* * *

4.0 Name of Natural Gas Supplier: ____________________

____

____

* * *

5.0 Is your facility an "industrial boiler fuel facility", as defined in the "Definitions" of this affidavit?

(a) ☐ No ... Sign and return affidavit.

(b) ☐ Yes ... Continue to 6.0.

* * *

6.0 Was your facility in existence on November 9, 1978, and did your facility, on the basis of records, documents or data in your possession, consume no more than an average of 300 Mcf per day as boiler fuel during any calendar month of calendar year 1977?

(a) ☐ Yes ... Sign and return affidavit.

(b) ☐ No ... Continue to 7.0.

* * *

7.0 Is all of the natural gas consumed as boiler fuel at your facility for an agricultural use?

(a) ☐ Yes ... Sign and return affidavit.

(b) ☐ No ... Continue to 8.0.

* * *

8.0 Is your facility, in its entirety, any of the following:

(a) A school, hospital, or similar facility?

☐ Yes ☐ No

(b) Used for generation of electricity by an electric generation station owned by an electric utility?

☐ Yes ☐ No

(c) A qualifying co-generation facility?

☐ Yes ☐ No

If the answer is "yes" to any of the above, sign and return this affidavit. If the answer is "no", continue to 9.0.

* * *

9.0 Is a portion, though not all, of the gas consumed at your facility used as boiler fuel for an agricultural use?

(a) ☐ Yes ... See "NOTICE" below.

(b) ☐ No ... Continue to 10.0.

* * *

10.0 Is your facility, in part, but not in its entirety, any of the following:

(a) A school, hospital, or similar facility?

☐ Yes ☐ No

(b) Used for the generation of electricity by an electric generation station owned by an electric utility?

☐ Yes ☐ No

(c) A qualifying co-generation facility?

☐ Yes ☐ No

If the answer is "yes" to any of the above, see "NOTICE" below, sign and return this affidavit. If the answer is "no" to all questions in Items 6.0 through 10.0, you should not return this affidavit.

* * *

NOTICE

If you have responded affirmatively to question 9.0, the volume of natural gas used in your facility which shall be exempt from incremental pricing: (1) for the period January 1, 1980, through October 31, 1980, may be determined on the basis of submetering determinations, monthly estimates which are certified by a responsible company official or on the basis of an agreement executed by you and your natural gas supplier; and (2) for the period beginning November 1, 1980, shall be determined on the basis of and to the extent there are submeter reading records for each calendar month, as signed under oath by a responsible company official, which show the extent to which gas is consumed for an agricultural use and which are furnished to the facility's natural gas supplier as required by the supplier. Certified monthly estimates or the agreement with your supplier may be utilized for a period following November 1, 1980, if you have obtained a purchase order for all submeters which will be needed in your facility by November 1, 1980, and expect installation within a reasonable time period.

If you have responded affirmatively to any part of question 10.0, the volume of natural gas which shall be exempt from incremental pricing: (1) for the period January 1, 1980, through October 31, 1980, may be determined on the basis of submetering determinations, monthly estimates which are certified by a responsible company official or on the basis of an agreement executed by you and your natural gas supplier; and (2) for the period beginning November 1, 1980, shall be determined on the basis of and to the extent there are submeters which permit determination of the volume of exempt usage and which are available to be read by the facility's natural gas supplier, or on the basis of and to the extent there are submeter reading records for each month, as signed under oath by a responsible company official, which show the extent to which gas is consumed for an exempt use and which are furnished to the facility's natural gas supplier as required by the supplier. Certified monthly estimates or the agreement with your supplier may be utilized for a period following November 1, 1980, if you have obtained a purchase order for all submeters which will be needed in your facility by November 1, 1980, and expect installations within a reasonable time period.

DATED: ____________________

Person completing this affidavit:

____
Name

____
Title

____
Phone number

Subscribed and sworn to before me this ______ day of ______________.

____
Notary Public

[¶ 30,086]

44 F. R. 57754 (October 5, 1979)

18 CFR Part 282

[Docket No. RM79-21; Order No. 50]

Regulations Implementing Alternative Fuel Price Ceilings on Incremental Pricing Under the Natural Gas Policy Act of 1978

AGENCY: Federal Energy Regulatory Commission.

ACTIONS: Final rule.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts regulations which set ceilings on the prices which can be charged to large industrial facilities under the incremental pricing program mandated by Title II of the Natural Gas Policy Act of 1978, for their use of natural gas as a boiler fuel. These regulations will result in large industrial users paying a price for their natural gas equivalent to the price they would pay for the fuel oil which they could burn as an alternative to natural gas.

EFFECTIVE DATE: December 1, 1979.

FOR FURTHER INFORMATION CONTACT:

Norman A. Pedersen, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8377.

Nancy E. Williams, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8033.

James C. Liles, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8158.

Regulations Implementing Alternative Fuel Price Ceilings on Incremental Pricing Under the Natural Gas Policy Act of 1978.

Issued September 28, 1979.

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I. Background

Title II of the Natural Gas Policy Act of 1978 (NGPA) (Pub. L. 95-621) requires that interstate pipelines and local distribution companies pass through certain portions of their natural gas acquisition costs to industrial users in the form of incremental pricing surcharges. Section 204 of the NGPA provides, however, that such surcharges may not cause the rates for natural gas charged to an incrementally priced industrial facility to exceed the appropriate alternative fuel cost of the facility. The regulations promulgated in this order provide for the determination of this ceiling on incremental pricing.

This "Final Rule" is a companion to the "Rule Exempting Industrial Boiler Fuel Facilities from Incremental Pricing Above the Price of No. 6 Fuel Oil" issued today in this docket and transmitted to Congress for its review pursuant to subsection 206(d) of the NGPA.[1] If Congress permits that exemption rule to become effective on December 1, 1979 as proposed, it will hold in abeyance until November 1, 1980 so much of the regulations prescribed herein as are inconsistent with having the ceiling on incremental pricing set at the price of No. 6 high sulfur fuel oil. After November 1, 1980, the "three-tier approach" to incremental pricing ceilings as adopted in this order would become effective.

Either House of Congress, however, may adopt a resolution disapproving the exemption rule at any time during the first 30 days of continuous session of Congress after a copy of the rule has been submitted to each House of Congress. If either House adopts such a resolution of disapproval, the "three-tier approach" as embodied in the regulations prescribed in this order shall become fully effective on December 1, 1979, no portion being held in abeyance.

This final rule is also a companion to the general incremental pricing rule issued today in Docket No. RM79-14.[2] That rule establishes a mechanism for incremental pricing in accordance with section 201 of the NGPA, and it establishes procedures for obtaining exemptions under section 206 of the NGPA.

The NGPA specifies that the incremental pricing program shall be implemented in two phases. The only facilities covered during the first phase, as required by section 201 of the NGPA, will be industrial facilities using large amounts of natural gas as boiler fuel. Title II requires that the regulations implementing this first phase be promulgated by November 9, 1979. The regulations adopted in this order apply to facilities affected by this first phase of incremental pricing.

During Phase II of the program, as provided by section 202 of the NGPA, incremental pricing may be extended to a broader class of industrial users than those affected by the first stage. The regulations implementing the second phase must be promulgated by May 9, 1980 and will be subject to Congressional review. Congress, by a veto by either House, may reject the Phase II rule proposed by the Commission.

II. Public Input to This Proposed Rulemaking

There has been extensive public participation at all stages of this rulemaking proceeding. Prior to the promulgation of the May 11, 1979 Notice of Proposed Rulemaking (44 FR 29090, May 18, 1979), the Commission's staff held a series of informal public conferences with state officials, representatives from the natural gas industry, natural gas end-users and other interested parties.

The first informal public conference regarding incremental pricing was convened on February 12, 1979 in Docket No. RM79-14. Notice of this conference was issued on January 12, 1979 (44 FR 6133, January 31, 1979). Though the primary subject of that conference was the incremental pricing mechanism, a number of participants expressed views about the alternative fuel price ceiling on incremental pricing.

On April 2, 1979, a public conference was called in this Docket, RM79-21, specifically to give interested parties an opportunity to discuss the issue of the ceiling. In the March 14, 1979 Notice convening the conference (44 FR 16937, March 20, 1979), participants were asked to discuss eight issues regarding establishment of the ceiling:

1. Should the alternative fuel cost ceiling be based on the cost of No. 2 fuel oil, the cost of No. 6 fuel oil or something in between?

2. What should be the regions for which alternative fuel cost ceiling should be determined?

3. Should the ceiling be based on the wholesale price of fuel oil or the retail price?

4. Should the alternative fuel cost ceiling be based on the price quoted for fuel oil before state and local taxes are included, or should the ceiling be based on the price after state and local taxes are included?

5. What should be the length of the period for which weighted averages should be taken in deriving alternative fuel cost ceiling from oil price data?

6. Should there be a downward adjustment of the average cost of oil? If so, what should be the factor by which there will be a downward adjustment?

7. How often should data on fuel oil prices be collected?

8. How frequently should the ceiling be published?

Many written and oral comments were received from parties with various viewpoints. Also, on April 12, 1979, the Commission staff met with members of the National Association of Regulatory Utility Commissioners to obtain data, views and comments regarding the ceiling from the perspective of state regulators.

After the issuance of the Notice of Proposed Rulemaking on May 11, 1979, hearings were convened in St. Paul, Los Angeles, Atlanta and Washington, D.C. Representatives of state agencies, the natural gas industry, end-users, and consumer groups appeared to present data, views, and arguments. Additionally, more than 50 written comments were submitted.

Lastly, the Energy Information Administration (EIA) distributed a consultation worksheet to selected potential respondents to Form EIA-194, the form which EIA will use to collect data to be used in generating alternative fuel price ceilings for each incremental pricing region. The consultation worksheets solicited the respondents' comments on a working draft of the form. Those worksheets are hereby made part of the public record in this proceeding.

III. The Ceiling Level: No. 2, No. 6 or Three-Tier?

The principal issue is whether the ceiling on incremental pricing should be set at the price of No. 2 (distillate) fuel oil, or whether statutorily specified conditions are met so that the Commission may exercise its statutory discretion to reduce the ceiling to some level not lower than the price of No. 6 (residual) fuel oil.

Congress intended Title II of the NGPA to provide a benefit to residential and commercial customers by directing first to industrial users the increase in natural gas acquisition costs which result from the NGPA. Those costs would otherwise, under conventional ratemaking principles, be borne by all customers—residential, commercial, and industrial—on an average volumetric or "rolled-in" basis.

Congress recognized, however, that for natural gas pipeline and distribution systems, industrial load provides a vital benefit to residential and commercial ("high priority") customers. The industrial customers bear capital costs which, if they left the system, would have to be borne entirely by the high priority customers.

If there were no ceiling on incremental pricing and, as a result, incremental pricing were permitted to take the price of gas above the cost of fuel oil, industries would find it to their benefit to switch from gas to oil. The result, of course, would be that capital costs which theretofore had been borne by industry would be shifted to residential and commercial customers. This would result in an increase rather than a decrease in the rates charged to the very customers that Title II was intended to benefit. To prevent such an anomalous result, section 204 of the NGPA provides that incremental pricing surcharges may not cause the rates charged for natural gas to an incrementally priced industrial facility to rise above the price of the "appropriate alternative fuel cost" of the facility.

It remains to be determined, however, what the "appropriate alternative fuel cost" of an incrementally priced facility might be. Subsection 204(e) provides that the "appropriate alternative fuel cost" shall be the price paid for No. 2 fuel oil in the region in which the facility is located, but the Commission is authorized to reduce the ceiling to a point not lower than the level of No. 6 fuel oil. Subsection 204(e) states:

> Sec. 204 Method of Passthrough
>
> * * * * *
>
> (e) Determination of Alternative Fuel Cost.—
>
> (1) In General.—Except as provided in paragraph (2), the appropriate alternative fuel cost for any region (as designated by the Commission) shall be the price, per million Btu's, for Number 2 fuel oil determined by the Commission to be paid in such region by industrial users of such fuel.
>
> (2) Reduction of Appropriate Alternative Fuel Cost Allowed.—The Commission may, by rule or order, reduce the appropriate alternative fuel cost—
>
> (A) for any category of incrementally priced industrial facilities, subject to the rule required under section 201 (including any amendment under section 202 to such rule) located within any region and served by the same interstate pipeline; or
>
> (B) for any specific incrementally priced industrial facility which is subject to such requirements and which is located in any region;
>
> to an amount not lower than the price, per million Btu's, for Number 6 fuel oil determined by the Commission to be paid in such region by industrial users of such fuel, if and to the extent the Commission determines, after an opportunity for written and oral presentation of views, data, and arguments, that such reduction is necessary to prevent increases in the rates and charges to residential, small commercial, and other high-priority users of natural gas which would result from a reallocation of costs caused by the conversion of such industrial facility or facilities from natural gas to other fuels, which conversion is likely to occur if the level of the appropriate alternative fuel cost were not so reduced.

The Commission interprets this subsection to indicate Congressional intent that the alternative fuel price ceiling should be kept at the level of No. 2 fuel oil unless it is likely that a No. 2 ceiling will result in fuel switching and a shifting of capital costs that would increase residential and commercial rates. If it is likely that a No. 2 ceiling would cause fuel switching and an increase in residential and commercial rates over what they would be if there were a lower ceiling, the Commission believes that Congress intended that the ceiling should be reduced to prevent such a likelihood. The Conference Report supports this interpretation:[3]

> The conferees urge the Commission to take whatever action it deems appropriate or necessary * * * to avoid any delays in reducing the substitute fuel level so as to avoid the likelihood of conversions from natural gas by industrial users if those conversions would result in increases in natural gas rates for any residential, small commercial, and other high priority customers. The conferees intend that in determining the likelihood of these conversions occurring, the Commission move rapidly in the administrative hearings so as to avoid the irreparable damage which the conferees believe will occur to high priority users if these other industrial users, faced with uncertain natural gas rates, begin taking steps to secure alternate fuel supplies.

The substantial dependence of the United States on imported oil adds special urgency to this Congressional admonition. If incremental pricing were permitted to induce increased industrial use of fuel oil, United States' dependence on imported oil would be exacerbated, contrary to the national interest.

However, while the Commission believes it is authorized to reduce the ceiling so as to minimize the likelihood of fuel switching and its adverse consequences, the Commission also believes that subsection 204(e) implies that Congress did not intend that the ceiling be reduced to the price of No. 6 fuel oil if such a ceiling would be likely to result in residential and commercial rates being higher than they would be with a No. 2 ceiling.

In view of the intent underlying subsection 204(e), in its May 11, 1979 Notice of Proposed Rulemaking the Commission considered the likely impact that a uniform No. 2 or No. 6 ceiling would have on residential and commercial rates. Additionally, the Commission endeavored to devise a system of multiple ceilings under which the ceiling applicable to any particular incrementally priced facility would be high enough to maximize the recovery of incremental costs from that facility, yet would be low enough to minimize the likelihood that the facility would switch to an alternative fuel. Such a scheme would seem to offer the potential to achieve the maximum possible flow-through of incremental costs to industrial boiler fuel customers without causing load loss.

Accordingly, the Commission proposed that three alternative fuel price ceilings be established for each region of the country. One ceiling would be set at the level of No. 2 fuel oil, another at the level of low sulfur No. 6 fuel oil and a third at the level of high sulfur No. 6 fuel oil. Each industrial boiler fuel facility would be incrementally priced only up to the level of the lowest priced fuel oil that it could in fact use. This approach would seem to avoid the establishment of a blanket ceiling for all users which might be too high for some, resulting in their loss to the system, while at the same time being too low for others, allowing them to escape some of the costs which Congress intended they should bear under the incremental pricing program.

On the basis of the data, views and arguments furnished during the extensive proceedings in this docket the Commission must decide whether, under subsection 204(e), the ceiling on incremental pricing should be reduced from the No. 2 level. If so, the Commission must determine whether the ceiling should be set at the price of No. 6 oil or whether the proposed three-tier method should be adopted.

A. Should there be a single-tier ceiling set at the price of No. 2 fuel oil?

The record in this proceeding shows that there are a large number of industrial boiler fuel facilities which have the capability to burn fuel oils which are cheaper than No. 2. Furthermore, the record shows that those facilities are price sensitive and would shift to oil if the price of gas charged to them were permitted to rise to the level of No. 2 fuel oil. Thus, setting the ceiling at the No. 2 level would seem lilely to have the results that Congress instructed the Commission to deter.

1. *Many industrial boiler fuel facilities are capable of burning fuel oil which is cheaper than No. 2 fuel oil.*—In connection with the conferences held before the issuance of the Notice of Proposed Rulemaking, a number of participants submitted data showing that, to a substantial extent, fuel oils other than No. 2 are the alternative fuels for industrial boiler fuel facilities that will be subject to incremental pricing. For example, the State of Louisiana commented that, in Louisiana, large industrial boilers equipped to burn No. 6 fuel oil outnumber by more than 3 to 1 boilers that are equipped to burn No. 2 fuel oil. Similarly, the Public Staff of the North Carolina Utilities Commission submitted an analysis of the industrial service currently provided by the Public Service Company, one of three gas utility companies serving North Carolina. This study showed that of industrial boiler fuel users served by that utility, 87.75 percent, based on volumetric use, have a capability to use No. 5 or No. 6 fuel oil.

In response to the Notice of Proposed Rulemaking, many commenters submitted similar data. For example, the South Carolina Public Service Commission surveyed the natural gas distributors subject to its jurisdiction. It found that, for sales of gas by subsidiaries of Carolina Energies, Inc., to facilities which may be subject to incremental pricing, 64 percent of the sales are to customers that use No. 6 high sulfur fuel oil as their alternative to natural gas. For South Carolina Electric and Gas Company, 84 percent of the sales are to industrial facilities which have a high sulfur No. 6 capability. The figure is 60 percent for United Gas Company and 100 percent for Peoples Natural Gas Company of South Carolina.[6]

Various distributors have testified to the same effect about the amount of industrial load on their systems which has the capability to use No. 6 as an alternative to gas. For example, of the gas sold by Consumers Power Company that may be subject to incremental pricing, 91 percent is sold to facilities with the capability to use No. 6 fuel oil.[5] The figure is 50 percent for Northern Natural Gas Company.[6] The Public Service Electric and Gas Company commented that 88 percent of the volumes it sold to industrial boiler fuel facilities were sold to facilities which could use No. 4 or No. 6 fuel oil.[7]

The various comments of state agencies, distributors, pipelines and industrial end-users about how a large number of industrial boiler fuel facilities have the capability to use No. 6 fuel oil as an alternative to gas agree with data made available to the Commission by the Energy Information Administration. These data were described in the Notice of Proposed Rulemaking in this docket.[8] They show that a substantial number of industrial boiler fuel facilities have the capability to use No. 6 fuel oil as an alternative to natural gas.

As for why some facilities have the capability to use the less expensive No. 6 fuel oil while some do not, commenters explained that No. 6 fuel oil is usually more difficult to use than No. 2. Due to its high viscosity, No. 6 fuel oil will not flow readily at normal or low temperatures without being heated. In order to use No. 6 fuel oil rather than No. 2, an industrial facility needs to have special equipment such as heaters in its fuel tanks and steam tracers on the pipes carrying the oil from the storage tanks to the burner tip.

For a small facility or a facility which needs oil only on an infrequent basis as a backup for gas in case of curtailment, it is often uneconomic to incur the capital cost of installing the capability to burn No. 6 fuel oil. And, even if it is economic, it simply may not be worth the effort of installing the equipment needed to burn No. 6 fuel oil.

As commenters pointed out, however, large industrial facilities or facilities which are curtailed more frequently are in a far different position. Due to their greater fuel requirements, these facilities have in many cases opted to incur the relatively modest capital costs of installing heaters and steam tracers so as to take advantage of the substantial ($1.00 or more per MMBtu) price differential between No. 2 and No. 6 fuel oil. Thus, for example, the record shows that at the 3–M Company, which operates over 100 facilities and plants in 28 states, both No. 2 and No. 6 fuel oil are used as alternative fuels. When asked at the St. Paul hearing why 3–M uses more expensive No. 2 fuel oil, the 3–M representative responded:

> Basically because of the size of the installation. They are relatively small facilities and small plants with a relatively low usage requirement.

Similarly, the representative of Georgia Kraft Company testified at the Atlanta hearing:

> The basic fuels for industrial energy as I know it as representative of a large manufacturer is No. 6 fuel oil—high sulphur No. 6 fuel oil.

In sum, the record in this proceeding demonstrates that there are a substantial number of industrial plants that have the capability to burn No. 6 fuel oil or that could easily and reasonably acquire such a capability. In general, use of No. 2 fuel oil is preferred only by small facilities or by facilities where gas use is so seldom interrupted that it is not worth the expense or bother to use No. 6 fuel oil.

2. *Industrial boiler fuel facilities are price-sensitive.* The record establishes, further, that industrial facilities that have residual fuel oil burning capability are price sensitive and will switch to fuel oil if gas is priced at the No. 2 level. For example, the representative of the Process Gas Consumer Group (PGC), the members of which own and operate over 1,000 plants in virtually every state, said that non-exempt industrial facilities "generally have the capability to switch on or off gas extremely rapidly." If incremental pricing pushes "gas prices above the price of the cheapest potential

alternate fuel, such users will not hesitate to switch off of gas."

PGC's view was shared by each of the other sixteen industries or industrial groups which responded to the Notice of Proposed Rulemaking. Kennecott Copper Corporation's Chino Mine Division, located in southwestern New Mexico, commented that non-exempt end users "have the ability to switch almost instantaneously to cheaper alternate fuels." The Hoerner Waldorf division of Champion International Corporation in St. Paul, Minnesota, testified:

> Since [Hoerner Waldorf's St. Paul] facility has the capability of using both natural gas and No. 6 fuel oil, it can switch to the lower cost of these fuels on very short notice. [A] difference of only one cent per million Btu would be sufficient incentive for one facility to switch to the lower cost fuel.

Similarly, the representative of George Kraft Company of Georgia and Alabama testified:

> My company can switch completely on or off natural gas in about 30 minutes' time, and we do it rather frequently. When gas prices approach oil prices on an equivalent Btu basis, we're going to shop among the alternatives that we have; and we're going to make that decision, as I said, on almost a daily basis.

The representative of 3–M Company testified that 3–M already has facilities "where we have already discontinued using natural gas because its price exceeds the cost of our alternate fuel."

The Commission concludes that not only does a large amount of incrementally priced industrial boiler fuel load have the capability to burn No. 6 fuel oil, but there is a strong likelihood that this load would shift from gas to oil if gas were priced at the level of No. 2 fuel oil.

3. *What would be the impact of a uniform No. 2 ceiling on high-priority customers?* As for the precise, total amount of incrementally priced load that would be lost if there were a uniform No. 2 ceiling, commenters disagree. The American Gas Association (AGA) surveyed its members and found that 40 percent more load loss would occur with a No. 2 ceiling than with a No. 6 ceiling. The Department of Energy, on the other hand, surveyed five distribution companies and found there would be a 50 to 80 percent load loss for those companies, if there were a No. 2 ceiling.

Based on the data in the record, then, the precise amount of load loss which would occur if there were a No. 2 ceiling cannot be established. Further, as the data submitted by the South Carolina Public Service Commission and others show, the amount of load loss would vary from distributor to distributor, depending on how much industrial boiler fuel load had No. 6 burning capability.

Commenters generally agreed, however, that the load loss which would result from a No. 2 ceiling would be substantial and would be disadvantageous to residential and commercial customers. The Commission notes, especially, that the National Association of Regulatory Utility Commissioners as well as the state regulatory commissions of California, Michigan, Ohio, North Carolina, South Carolina and Wisconsin strongly argued against a uniform No. 2 level on this ground. The comment of Chairman Daniel J. Demlow of the Michigan Public Service Commission was representative:

> Our initial concern was that the target price based on the cost of the No. 2 fuel oil would result in the loss of considerable volumes of gas sales to non-exempt boiler fuel facilities. We affirm this concern here. Several boiler fuel customers of gas utilities in Michigan have already converted from gas to residual fuel oil because current firm industrial gas rates are approximately equal to the cost of residual fuel oil. This loss of load has already resulted in significantly increased costs to residential and other high priority gas customers in Michigan.

Several other state and local authorities who provided comments in response to the Notice of Proposed Rulemaking supported the view that the extent of load shifting that would be induced by a No. 2 ceiling would disadvantage the high-priority consumers they represent. Among these were the Mayor of St. Paul, Minnesota; the Director of Minnesota Office of Consumer Services and the representative of the Georgia Consumers' Utilities Council. They echoed the view of the state regulatory commissions that the Commission must lower the ceiling from the No. 2 level in order to protect residential and commercial customers.

The Federal Energy Regulatory Commission gives great weight to the expert judgment of the state and local officials who testified or contributed comments. They are familiar with local industrial fuel usage patterns, and they are in a position to be acutely aware of the likely consequences of industrial load loss on residential and commercial consumers. Moreover, they have special responsibilities with respect to the interests of these groups.

The Commission concludes that a No. 2 ceiling on incremental pricing would be likely to cause substantial load switching, and the loss of such load would be likely to result in a shifting of capital costs to the disadvantage of high-priority customers.

The question remains, however, as to whether these customers would be better off with an incremental pricing ceiling set at the price of No. 6 fuel oil rather than at the price of No. 2 fuel oil.

B. Should the ceiling be reduced to the level of No. 6 fuel oil?

In view of the substantial load loss that might occur with a ceiling based on the price of No. 2 oil, the American Gas Association (AGA) as well as other commenters urged that there be a uniform incremental pricing ceiling set at the level of No. 6 fuel oil.

AGA supported its argument for a uniform No. 6 ceiling by submitting a study purporting to show that, on a national average basis, residential and commercial rates would be lower with a uniform No. 6 ceiling than with a No. 2 ceiling. AGA surveyed 41 of its member companies to determine the industrial load loss they would incur if there were a uniform No. 2 ceiling on incremental pricing. Based on the results of that survey, AGA concluded that if the alternative fuel price ceiling were established at the No. 2 rather than No. 6 level, 741 to 788 billion cubic feet (Bcf) of industrial boiler fuel sales would be lost in 1980.[9] This represents 39 percent to 41 percent of the total 1,900 Bcf of industrial boiler fuel sales that AGA projects for 1980.

AGA then attempted to estimate the effect of the loss of approximately 800 Bcf of industrial sales on residential gas rates. AGA projected 1981 residential rates under two simplified scenarios. Under the "Low Cap Scenario", it was assumed that industrial boiler fuel facilities would be incrementally priced at the estimated 1981 price of low sulfur (0.3%) No. 6 fuel oil, $3.50 per MMBtu. Further, it was assumed that no load loss would be caused by incremental pricing. Under the "High Cap Scenario", it was assumed that industrial boiler fuel facilities would be subject to incremental pricing at the projected level of the price of No. 2 fuel oil in 1981, $4.10 per MMBtu, and that 800 Bcf of industrial sales would be lost.

AGA concluded that rates to residential and commercial customers would be higher under the High Cap Scenario than under the Low Cap Scenario. Under the High Cap Scenario, the national average charge for providing gas to residential and other high-priority customers in 1981 would be $3.21 per MMBtu, 12 cents more than the $3.09 per MMBtu that AGA estimated would be charged under the Low Cap Scenario.

According to the AGA study, the higher charge would be attributable to three factors. First, an additional 5 cents per MMBtu would have to be charged under the High Cap Scenario to recover fixed transmission and distribution costs since there would be fewer sales from which to recover those costs. Second, additional seasonal and peak shaving costs would raise rates by 2 cents per MMBtu. Third, the total amount of incremental costs that could be absorbed by industrial customers would actually be $495 million less under the High Cap Scenario, resulting in a 5 cents per MMBtu increase in high-priority customer rates.[10]

AGA concluded that the Commission should establish a uniform ceiling on incremental pricing at the level of "the lowest cost appropriate alternative fuel."

The Department of Energy, however, submitted a more complex study using a more sophisticated methodology that raises substantial doubts about the AGA conclusion that a ceiling set at the No. 6 level would generally benefit high-priority consumers.

In transmitting the study, Secretary of Energy James R. Schlesinger expressed the Department's view, that it is in the national interest for natural gas be used to displace more costly imported oil. Thus, the Secretary stated, the Department would prefer to have the ceiling on incremental pricing set at the level of high sulfur No. 6 fuel oil.

Secretary Schlesinger went on to say, however, that, in the Department's view, if adoption of a uniform No. 6 ceiling decreased the surcharge absorption capability of incrementally priced facilities so much that, in at least some cases, the reduction would offset the benefit to high-priority customers of avoiding load loss, then, under subsection 204(e) of the NGPA, the ceiling should not be reduced to a uniform No. 6 level. In other words, the test for whether the ceiling should be reduced to the price of No. 6 fuel oil is "whether the total revenue over and above the cost of natural gas paid by fewer incrementally priced users at a distillate price would be greater than the total revenue over and above the cost of natural gas paid by more incrementally priced users at a lower price."

The Department of Energy's study suggests that it is problematical as to whether a No. 6 ceiling would benefit high-priority customers more than a No. 2 ceiling. Thus, although the Department of Energy would have preferred a uniform No. 6 ceiling on the basis of public policy considerations, Secretary Schlesinger supported the Commission's proposed three-tier approach as a reasonable way to conform to the mandate of Title II of the NGPA.

DOE studied the effect that industrial boiler fuel load losses of 40 percent, 50 percent, 66.7 percent and 80 percent would have on the high-priority customers of 38 distribution companies. DOE first analyzed the effect such load losses would have, based on May, 1979 oil prices.[11] DOE found that in May residential and commercial customers would have been better off with a ceiling set at the No. 2 rather than No. 6 level. This held true regardless of whether load loss were assumed to be at the low extreme of 40 percent or at the high extreme of 80 percent.

DOE found, further, that the effect of load loss was dependent on the level of oil prices. June prices were projected by DOE to be substantially higher than May's. While May, 1979 prices reflected world crude oil prices of $15.00 per barrel, DOE projected that June, 1979 prices would reflect world prices of $19.60 per barrel.[12] As a result, since the cost of gas would be relatively unchanged, the amount that could be collected from industrial customers at a high sulfur No. 6 ceiling would be significantly greater in June than in May. Accordingly, while in May high-priority customers would have been better off with a No. 2 ceiling even if there had been load loss of 80 percent, in June such customers would be better off with a No. 2 ceiling only if load loss stayed below a point in the range of 50 percent to 66.7 percent.

In either case, however, the results of the DOE study contrast strikingly with AGA's contention that high priority customers would be *worse* off with a No. 2 ceiling even with load loss as low as 40 percent. Several important differences between the AGA and DOE studies explain the divergent results.

One difference was that different grades of No. 6 fuel oil were used in the two studies. The price of No. 6 fuel oil varies significantly on the basis of sulfur content, with high sulfur No. 6 fuel oil being less expensive than low sulfur No.

6 oil.[13] Thus, high sulfur No. 6 oil is preferred by industrial users, and a No. 6 ceiling has to be set at the price of high sulfur No. 6 fuel oil if it is to be assumed that no load loss will occur. Accordingly, DOE used an average price for high sulfur (1.0 percent and above) No. 6 fuel oil in estimating the amount industrial boiler fuel facilities could be charged if they were billed at a No. 6 ceiling. AGA, however, used a projected price of the more expensive low sulfur (0.3 percent) No. 6 fuel oil in deriving its "low cap" ceiling. The effect of using a low sulfur No. 6 oil price was that AGA overstated the contribution that incrementally priced industries would make to high-priority customers if there were a "Low Cap" ceiling.

A second difference between the DOE and AGA studies was that AGA measured the 1981 contribution per MMBtu of industrial customers to high-priority customers by subtracting the projected average retail industrial rate ($2.35 MMBtu) from the alternative fuel price ceilings.[14] DOE's study points out, however, that what an industrial customer contributes to recovery of system costs and thus, to the high-priority customers is the amount the industrial customer is charged in excess of the actual marginal cost of the gas acquired to serve him.

Stated differently, the cost of supplying an additional MMBtu of gas to an industrial customer is equal to the highest wellhead price paid by the supplying interstate pipeline plus variable conditioning and transportation costs and taxes. If an industrial customer leaves the system, the highest priced gas which otherwise would be purchased to serve the industrial customer would not be purchased. As a result, the average "rolled-in" cost of gas would be reduced to the benefit of the remaining customers. DOE's methodology captured this benefit which would be gained by the high-priority customer if there were industrial load loss.[15] AGA's method did not.[16]

Lastly, DOE did not concur with AGA that load loss resulting from a No. 2 ceiling would result in additional storage costs. Industrial customres are not storage facilities. Having them as customers permits a lessening of capital charges per unit by permitting a higher load factor during off-peak periods. Consequently, if they were lost from a system, capital charges to high-priority customers would be higher. But no less gas would be available to those high priority customers during peak periods. Thus, the loss of industrial customers would not, in itself, give rise to a need for additional storage facilities.

More importantly than these methodological differences, however, DOE's study illustrates the inherent and quantitatively unresolvable uncertainty about whether lowering the ceiling from the price of No. 2 fuel oil to the level of No. 6 oil would benefit residential and commerical customers. As has been discussed above, there is uncertainty about the amount of load loss which would occur if there were a No. 2 ceiling. DOE's study shows that there is a second—and even more serious—concern. While something between 50 percent and 66 percent load loss would have justified a No. 6 ceiling in June, 1979, only one month earlier not even an 80 percent load loss would have justified a No. 6 ceiling.

Thus, while it may be possible to determine whether a No. 6 ceiling is justified on the basis of data for one month, the ceiling might not be justified for another month. As DOE's figures for May and June, 1979, illustrate, changes in world oil prices can transform either a No. 6 or No. 2 ceiling from a benefit to a detriment to high-priority customers. There is high and inherent uncertainty about the future course of world oil prices as well as inherent but less uncertainty about the future price of gas, and such uncertainty obviates the possibility of determining whether, in the future, high-priority customers would be benefitted by a No. 6 rather than a No. 2 ceiling on incremental pricing.

C. The Three-Tier Approach

With the three-tier approach proposed in the May 11, 1979 Notice of Proposed Rulemaking, the Commission sought to steer, as the Notice put it, between the Scylla and Charybdis of No. 2 and No. 6 ceiling levels.

As commenters pointed out, subsection 204(e) of the NGPA does not require that the Commission devise and adopt a scheme that would minimize residential and commercial rates. It only requires that for the Commission to reduce the ceiling on incremental pricing from the price of No. 2 fuel oil, it must be likely that such a reduction would result in lower residential and commercial rates than would an unreduced No. 2 ceiling. Yet, the three-tier approach not only satisfies that statutory requirement, it also maximizes the benefits of incremental pricing for high-priority customers.

To demonstrate this, DOE submitted the stylized demand curves set forth in Figures 1 and 2. As Figure 1 shows, if there is a "single-tier" ceiling set at the price of No. 2 fuel oil, there will be an increase in the contribution to system costs per unit of incrementally priced gas. Due to load loss, however, less gas will be subject to incremental pricing. On the other hand, a No. 6 ceiling will decrease the per unit contribution but will increase the volume of gas subject to incremental pricing. Thus, using DOE's Figure 1, the ceiling should be lowered from the price of No. 2 fuel oil to the price of No. 6 oil if area R is larger than area D. As just discussed, however, not only is there insufficient information to determine which area is larger at a given point in time, but the size of the areas will change over time.

These problems inherent in trying to determine the relative sizes of areas D and R are avoided under the three-tier approach, as shown in DOE's Figure 2.

The advantage of the three-tier ceiling is that by keeping the No. 6 fuel oil customers on the system, it avoids load loss without reducing the contributions from the distillate customers: area T in Figure 2 is always greater than area D because D is included in T. Similarly, area T is always greater than areas L or H, illustrating that a three-tier ceiling will always provide greater benefits to residential and commercial customers than either a low sulfur No. 6 ceiling as used in AGA's study or a high sulfur No. 6 ceiling as used in DOE's study.

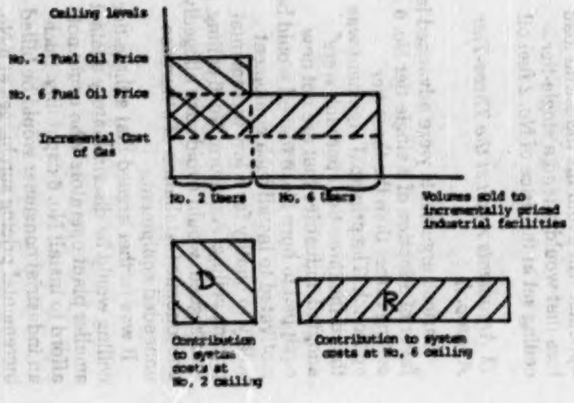

FIGURE 1

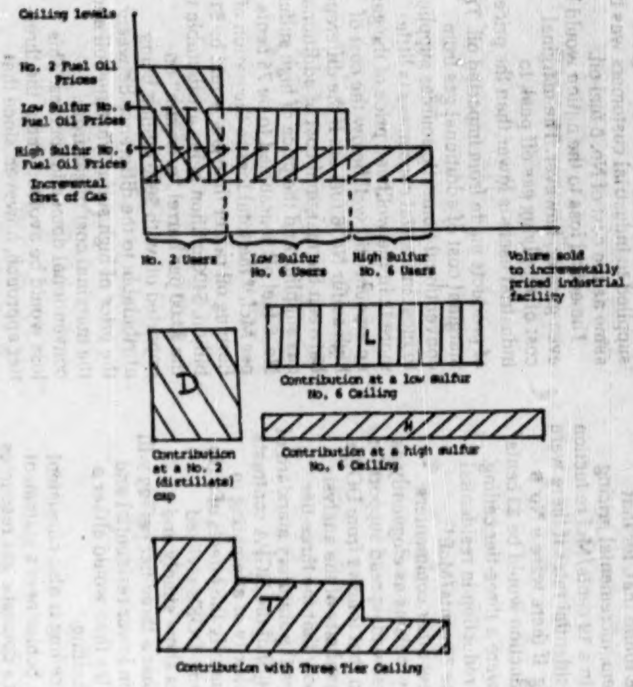

FIGURE 2

DOE went on to examine a sample pipeline. DOE found that, for that pipeline system, incremental pricing would result in a 19 cents/Mcf reduction in average residential rates if there were a No. 2 ceiling. If there were a No. 6 ceiling the reduction would be 23 cents/Mcf. If there were a three-tier ceiling, however, the reduction in residential rates would be 28 cents/Mcf.[17]

Although few other commenters analyzed the problems as eloguently as DOE, there was widespread support for the conclusion that follows from DOE's model. The simplicity of the analysis required to show that the three-tier ceiling satisfies the statutory standard of subsection 204(e) of the NGPA contrasts with the complexity of attempting to predict and quantify the effects of a No. 2 or No. 6 ceiling. DOE's stylized demand curves show simply and convincingly that a three-tier ceiling will always result in lower residential and commercial rates than would either a No. 2 or No. 6 ceiling.

A three-tier ceiling is also consistent with Secretary Schlesinger's statement that the nation's domestic gas resources should be used to displace imported oil. In the DOE study tendered in support of Secretary Schlesinger's comment in this proceeding, DOE observed that the use of gas to displace imported oil creates three types of benefits: downward pressure on world oil prices, reduction in the chance and cost of interruption, and reduction in the balance of payments deficit. DOE estimates suggest that the value or "premium" on reducing imports is about $3.00 per barrel, or about 50 cents per Mcf, above the world oil price.

As mentioned above, AGA estimated in its comments that if there were a No. 2 fuel oil ceiling on incremental pricing, industrial users of approximately 800 Bcf per year would switch from No. 2 to No. 6 fuel oil. This would result in a U.S. demand for imports of about 400,000 barrels per day. Thus, based on the $3.00 per barrel "premium" on imported oil, the loss to the nation from an increase in imported oil due to there being a No. 2 ceiling would be over $400 million per year, assuming that the cost of gas supplied to industrial customers was the same as the cost of No. 6 fuel oil.

The actual loss to the nation would be even greater, however. The marginal cost of supplying gas off peak to industrial users is lower than the price of products made from imported oil. The marginal cost of additional gas from conventional domestic sources supplied to most industrial consumers is little more than the wellhead price of the gas, an amount still well below the cost of high sulfur No. 6 fuel oil. If the difference between the marginal cost of additional gas supplies and the price of high sulfur No. 6 fuel oil is assumed to be 75 cents per Mcf,[18] the total loss to the nation of burning oil rather than gas would be $1 billion, $400 million being attributable to the $3.00 per barrel "premium" on imported oil with $600 million being attributable to the difference between the price of high sulfur No. 6 fuel oil and the marginal cost of gas from conventional domestic sources. This loss would be avoided under the three-tier approach, however, since that appoach will avoid the industrial load loss that would attend a single-tier ceiling set at the price of No. 2 fuel oil.

D. Arguments Against the Three-Tier Approach

Various arguments were advanced in favor of adoption of a single-tier No. 6 ceiling rather than the three-tier approach. The principal argument was that if the three-tier approach were adopted, industries that are not now equipped to burn No. 6 fuel oil would be motivated to install such equipment solely to qualify for a low incremental pricing ceiling. A uniform No. 6 ceiling, it was argued, would avoid such allegedly uneconomic installation of otherwise unneeded equipment.

It was further argued that a three-tier ceiling would be discriminatory against smaller plant operators who could not afford to install No. 6 capability. Such an industrial consumer would be billed incremental pricing surcharges at a No. 2 level although his larger and wealthier competitors could afford to install No. 6 capability so as to avail themselves of the lower No. 6 ceiling.

Additionally, it was argued that a single-tier No.6 ceiling would pose less of an administrative and enforcement burden than would a three-tier ceiling, and that a No. 6 ceiling would be environmentally beneficial.

In the companion order issued today in this Docket, the Commission has expressed its concern that the three-tier approach may induce significant investment in No. 6 oil burning capability solely to gain the advantage of a lower incremental pricing ceiling. The amount of this induced investment cannot be estimated with precision, but the record indicates that it could be a sizable amount. Thus, the Commission is extremely concerned about letting the three-tier approach go into effect without further time to gain familiarity with the incremental pricing program, the industrial facilities which will be incrementally priced, and the extent to which the three-tier approach would be likely to result in an inducement to install otherwise unneeded No. 6 oil burning equipment.

Accordingly, in the companion order the Commission provides for an exemption under subsection 206(d) of the NGPA to hold the upper two tiers of the three-tier system in abeyance for 10 months from January through October, 1980, to provide a period in which a better understanding of the implications of the three-tier approach can be obtained.

The Commission is also concerned about the administrative and enforcement burden which will be occasioned by the three-tier approach. As noted by the Commission in the companion order, a further benefit of the 10 month exemption is that having a single-tier ceiling during at least the first few months of incremental pricing will ease implementation of an effective program. Perhaps most importantly, the likelihood of there being erroneous ceiling prices which cause load loss would be minimized.

As for the environmental argument for a single-tier No. 6 ceiling, the Commission's Environmental Assessment indicates that a three-tier rather than No. 6 ceiling would not have any adverse environmental impact.

However, the Commission observes in the companion order that the 10 month exemption would provide an opportunity to evaluate further the environmental implications of the three-tier approach with the benefit of having the incremental pricing program actually in place.

One commentator argued that there should be a single ceiling at the No. 2 fuel oil level rather than a three-tier ceiling. The National Consumer Law Center, Inc., (NCLC) urged that the Commission avoid the load loss which would result from a No. 2 ceiling by taking steps to insure the availability of gas to industrial users in return for them being incrementally priced at a level higher than their alternative fuel capability. NCLC, however, did not explain how the Commission is to overcome the apparent jurisdictional barriers to it exercising curtailment authority over retail sales of distribution companies subject to state or local regulation. Nor did NCLC present any information on how much load loss could be avoided by assuring supply to incrementally priced end-users, assuming the Commission had authority to achieve such an end.

The Commission concludes that the three-tier approach as proposed in the Notice of Proposed Rulemaking best satisfies the Congressional intent underlying subsection 204(e) of the NGPA. Accordingly, that approach is adopted in this final rule. However, due to the concerns discussed above and discussed in greater detail in the companion order issued today in this docket, the Commission, in that companion order, finds that it would be appropriately cautious and in the public interest to hold the upper two tiers in abeyance for 10 months until November 1, 1980.

IV. Other Issues Regarding the Ceilings on Incremental Pricing

Given that a three-tier ceiling is superior to having a single-tier ceiling either at the No. 2 or No. 6 level, a question arises about whether there should be more than three tiers. Particularly, should there be additional tiers for blends of No. 2 and No. 6 fuel oil and for the different No. 6 fuel oils, the cost of which varies according to sulfur content. Additionally, there is a question about how to handle alternative fuels other than oil.

A. Blends

No. 4 and No. 5 fuel oil are usually obtained by blending No. 2 and No. 6 oil. Thus, they are generally cheaper than No. 2 oil, but more expensive than No. 6. In the Notice of Proposed Rulemaking, it was proposed that facilities which had the capability to use No. 4 or No. 5 fuel oil would be incrementally priced at the No. 2 level.

Parties objected, saying, most frequently with reference to No. 5 fuel oil, that if facilities which had the capability to burn a blended fuel oil were incrementally priced at the level of No. 2 fuel oil, the price of gas would be pushed above the price of their alternative fuel, and they would leave the gas system.

Several solutions were urged upon the Commission. One was to add two tiers, one reflecting the price of No. 4 fuel oil and one reflecting the price of No. 5, to the proposed three-tier approach. In response, the Commission notes that there is enough of an administrative and enforcement burden with a three-tier approach without stretching the limits of administrative feasibility yet further with a five-tier ceiling. Further, it is apparent to the Commission that EIA will have difficulty enough implementing the three-tier approach without having to generate five ceiling prices for each incremental pricing region of the country.

Another suggestion was to use a "weighted average" of the prices of No. 2 and No. 6 fuel oil to derive the ceiling prices for No. 4 and No. 5 fuel oil. There is, however, no evidence in the record suggesting any systematic correlation between the prices of No. 2 and No. 6 fuel oil on the one hand and the prices of No. 4 and No. 5 on the other. Further, there is no evidence of the ratio of No. 2 to No. 6 fuel oil which is used—if one is consistently used—in blending to get No. 4 or No. 5 oil.

A third suggested approach was to let the low sulfur No. 6 ceiling apply to a facility which has the capability to burn blended fuel oil. The Commission shall adopt this solution with regard to No. 5 oil. No. 5 is only slightly more expensive than low sulfur No. 6 fuel oil. Thus, relatively little surcharge absorption capability is lost if facilities capable of using No. 5 fuel oil are priced at the low sulfur No. 6 level. And more importantly, No. 5 oil shares many of the characteristics of No. 6 fuel oil: it has a high viscosity which requires special equipment for it to be burned.

No. 4 oil, however, does not resemble No. 6 oil in its characteristics. Indeed, due to its lower viscosity, in many instances it can be burned in facilities equipped to burn No. 2 fuel oil. Thus, if end-users were permitted to have a No. 6 ceiling apply to them on the basis that they were capable of burning No. 4 fuel oil, there would be a danger that a No. 6 ceiling could be claimed by end-users whose alternative fuel was actually No. 2 fuel oil. Accordingly, this final rule will not permit the user of No. 4 oil to avail himself of a No. 6 ceiling. However, the Commission notes that such a user may seek an adjustment as provided in subsection 502(c) of the NGPA and section 1.41, of the Commission's regulations.

B. Sulfur Levels

Several parties commented that since the price of No. 6 fuel oil varies with sulfur content, each level of sulfur content should be treated as a separate alternative fuel with its own ceiling level. Accordingly, the Associated Gas Distributors (AGD) proposed that separate ceilings be established for No. 6 fuel oils with sulfur contents of 0.3 percent, 0.5 percent, 1.0 percent and 1.5

percent and above. CF&I Steel Corporation (CF&I), on the other hand, stated, "No. 6 fuel oil is normally marketed at at least three different gradations of sulfur content—0.3 percent sulfur content, 1.0 percent sulfur content and 2.2 percent sulfur content." Accordingly, CF&I urged that ceilings be set for each of those three grades of No. 6 fuel oil.

There is, however, a limit to the number of levels for which data can be collected and ceilings published on a monthly basis. As stated above, it is going to be difficult enough for that task to be performed with only three ceiling levels, without compounding the difficulty by trying to add ceiling levels.

A related concern has to do with establishing the breaking point between high and low sulfur No. 6 fuel oil. In the Notice of Proposed Rulemaking "low sulfur" fuel oil was defined as oil containing one percent or less sulfur. Conversely, "high sulfur fuel oil" was defined as being oil containing more than one percent sulfur. The Michigan Commission recommended that high sulfur oil be defined as including one percent or more sulfur with low sulfur No. 6 being defined as including less than one percent sulfur. The Commission believes, however, that the definitions in the Notice of Proposed Rulemaking would more closely comport with common practice in the oil industry.

United Distribution Company (UDC) urged the Commission to adopt a yet lower breaking point of .75 percent sulfur. This, however, would go too far toward permitting a "high sulfur" ceiling for facilities which actually may only use what is commonly accepted as being low sulfur fuel.

C. Alternative Fuels Other Than Oil.

Air Products and Chemicals, Inc., (Air Products) and the Chemical Manufacturers Association (CMA) said that some firms utilize alternative fuels other than oil (e.g., waste products, ethane, or refinery off-gas). Further, these fuels are priced at parity with the price of No. 6 fuel oil, since that is the fuel with which they compete. Yet, the facilities using the parity-priced alternative fuels frequently cannot burn No. 6 fuel oil and would, under the proposed regulations, be incrementally priced at the No. 2 fuel oil level. Accordingly, Air Products and CMA asked that a facility be incrementally priced at a No. 6 level if it certifies that it has available for purchase and is technically and legally permitted to burn an alternative fuel which is priced at parity with high or low sulfur No. 6 fuel oil.

Further, Potlatch Corporation urged that facilities which use alternative fuels such as coal, wood or spent pulping liquor be permitted to have incremental pricing ceilings set at the price of the alternative fuel or the price of No. 6 fuel oil, whichever is higher, regardless of whether or not there is parity pricing.

The Commission is not authorized under subsection 204(e) to base the appropriate alternative fuel cost for a facility on the costs of a fuel other than oil. Thus, ceiling levels shall not be established so as to recognize alternative fuels other than oil.

V. Regions

In the Notice of Proposed Rulemaking, the Commission proposed to establish incremental pricing ceilings for 39 separate regions. There would be eight large, multistate regions and 31 metropolitan regions. The eight large multistate regions were derived by modifying various regional divisions used by the Bureau of the Census, the Department of Energy and others to take into account energy production, distribution and sale patterns.

The 31 metropolitan areas reflected either Standard Metropolitan Statistical Areas (SMSA's) or Consolidated Metropolitan Statistical Areas (CMSA's) of one million or more in population, as determined by the Bureau of the Census of the United States Department of Commerce. Like SMSA's and CMSA's, the metropolitan regions observe county boundaries.

Alaska and Hawaii were not included in any of the regions, since neither state will be affected by the incremental pricing program. Neither presently utilizes gas from nor produces gas for the interstate market.

The metropolitan/multistate region approach would permit the establishment of incremental pricing ceilings which, to a substantial degree, would reflect market conditions in discrete marketing areas. There would be a relatively small dispersion of observed prices around the mean for each region, and sample size would probably be adequate. The nation's larger industrial and oil marketing concentrations are recognized, and state or county boundaries are followed.

NARUC and other commenters expressed the view, however, that the multistate regions are too large. As an example, NARUC cited the Southeastern region which extends from Virginia to Mississippi. NARUC observed that oil prices in the southeast vary between Atlantic and Gulf ports. Further, differences in transportation costs give rise to substantial oil price differences between inland and coastal areas.

Other commenters shared NARUC's concern. Alabama Gas Corporation said that Alabama and Mississippi are affected by Gulf coast prices which, at the time Alabama Gas filed its comments, had been averaging $2.00 per barrel less than Atlantic coast prices. South Carolina Electric and Gas Company (SCE&G), on the other hand, was particularly concerned about the difference in No. 6 oil prices between coastal and piedmont areas in the southeast.

The root of the concern expressed by NARUC, Alabama Gas, SCE&G and others seems to be that if incremental pricing ceilings are based on data for a region as large as the Southeastern multistate region, the ceilings may be low enough to forestall fuel switching, for example, on the Atlantic coast, but not on the Gulf coast. Similarly, the ceilings might prevent fuel switching in, for example, the piedmont area of Region 34, but there may be coastal areas of the Southeastern region where oil transportation costs are so low that oil will sell for less than gas priced at the incremental pricing ceiling.

This could well occur if ceiling prices were to be nothing more than weighted average oil prices. However, in the Notice of Proposed Rulemaking the Commission proposed that in deriving a ceiling price, weighted average oil prices would be adjusted downward to the higher of either the lowest observed price or a point two standard deviations removed from the mean. This would reduce the ceiling so much that it would be rare for an oil price to be lower than the ceiling. Nevertheless, the Commission notes the concern voiced by commenters about the size of the multistate regions.

A further concern that was mentioned by a number of commenters was that some distribution service areas would be divided between two or more regions. SCE&G's service area, for example, would be divided among three: New York (Region 3), Hartford (Region 2) and the New England multistate region. East Ohio Gas Company's (East Ohio) service area would be split between Cleveland (Region 13) and the Midwestern multistate region.

These and other commenters argued that having different industrial rates in the same service area would impose an administrative burden on distributors. Additionally, it would create price differentials between industrial facilities even though the facilities secure fuel supplies in the same market. Thus, East Ohio pointed out, price differentials could be created between competitors producing the same products in, for example, Akron and Canton, though they are less than 20 miles apart. Lastly, having different ceilings for the same service area would be contrary to traditional ratemaking principles. There would be different ceiling prices for industrial customers in Akron and Canton although the costs of serving them, and the alternative fuels available to them, are the same.

A variety of alternative proposals were made for modifying the proposed regions. NARUC, the Wisconsin Public Service Commission and several others urged that ceilings be determined for states. This, it was argued, would ameliorate the apprehension caused by having large multistate regions such as the Southeastern region. In any event, as the Wisconsin Public Service Commission pointed out, use of states as regions would prevent the ceiling prices in one state from being affected by the oil price conditions in other states. Lastly, Wisconsin observed, "There is much to be gained in terms of policy coordination and control by basing regions on political boundaries."

Other commenters, focusing particularly on the southeast, proposed that different ceilings be determined for coastal and piedmont areas even within the same state.

A number of parties who were particularly concerned about the "split service area" problem proposed that ceilings be determined for each service area. As an alternative, East Ohio proposed that if more than half of a distribution company's industrial sales volumes occur in only one of the incremental pricing regions among which the service area is divided, then the company should be permitted to use the ceilings as established for that region throughout the company's service area. United Distribution Companies (UDC) and Natural Gas Pipeline Company of America supported similar proposals.

Lastly, several parties urged that ceilings be determined for more than the 31 largest metropolitan regions. AGA urged that the original 31 metropolitan regions be supplemented to include the 60 metropolitan areas which have the highest rates of energy consumption. Others suggested particular additions to the list of metropolitan regions. For example, UDC asked that Syracuse and Rochester, New York; Charleston, West Virginia; Dayton and Toledo, Ohio; Springfield, Illinois and Kalamazoo, Michigan be added.

Upon considering these suggestions, the Commission will add states to the list of regions for which ceilings shall be published. This, combined with the fact that weighted average prices will be adjusted downward in deriving published ceilings, will eliminate the problems feared by commenters from the southeast. Further, in response to NARUC, the Wisconsin Commission and others, the use of states as regions will result in a more adequate recognition of state boundaries.

However, the multistate regions will not be discarded entirely. There may be states with such a low level of industrial oil usage that a statistically valid sample of industrial oil prices cannot be obtained. If such instances arise, the ceilings which will be published for the state shall be derived from data for the multistate region in which the state is located. Accordingly, while the multistate regions will not be incremental pricing regions for which ceilings shall be published, they will continue to have a function and will be described for informational purposes in the final regulations.

As for adding more metropolitan regions to the present list of 31, the Commission will not expand the list at this time. While it appears that it will not pose as substantial an additional burden on EIA to generate ceiling prices for the states as was originally anticipated, it does appear that it would be burdensome, especially at the outset of the incremental pricing program, to add to what EIA already finds to be a troublesome list of metropolitan regions.

EIA currently anticipates that it will be significantly more difficult to develop ceilings for the metropolitan regions than for states. Accordingly, while the Commission urges EIA to develop ceiling prices for both the contiguous 48 states and the 31 metropolitan regions on December 20, 1979 for use in January, 1980, the final regulations will require only that ceilings be published for the 48 contiguous states as of December 20. However, the ceilings must be published for all 79 regions—48 states and 31 metropolitan regions—no later than October 20, 1980. This will allow EIA up to 10 additional months to perfect its system for developing ceiling prices for the metropolitan regions. Until ceilings are available for metropolitan regions, the ceilings published for states shall be used without regard to the 31 metropolitan regions.

Lastly, the Commission is concerned about the split service area problem. The Commission will adopt a variant of the solution proposed by East Ohio. If a distribution company provides service in a geographically unified service area which is divided among two or more incremental pricing regions, and more than half of the company's incrementally priced industrial sales occur in only one of the regions, the company may so certify and use the ceiling for that region for its entire service area. If a company has a split service area problem but does not have at least 50 percent of its sales in any one of the incremental pricing regions among which its service area is divided, the company may file a petition to nominate which regional ceilings shall apply for its entire service area.

VI. Certification of Alternative Fuel Capability

In the Notice of Proposed Rulemaking, the Commission proposed that there would be a certification procedure for determining the alternative fuel capability of industrial boiler fuel facilities. If a facility were technically able and legally permitted to burn low sulfur No. 6 fuel oil, or if a facility were technically able and legally permitted to burn high sulfur No. 6 fuel oil, a responsible official of the facility could so certify. If there were such a certification, the facility would be incrementally priced at the level of the lowest priced alternative fuel—No. 6 low sulfur fuel oil or No. 6 high sulfur fuel oil—which the facility had been certified as being capable of burning. If there were no such certification of legal and technical capability to burn either low or high sulfur No. 6 fuel oil, a non-exempt facility would be deemed to have the capability to burn No. 2 fuel oil and would be incrementally priced at that level.

Certifications would be made through the filing of an alternative fuel capability affidavit, signed under oath by a responsible company official, with the Commission.[19] A copy of the executed affidavit would be filed with the natural gas supplier serving the facility. Blank affidavits would be supplied to industrial customers by their suppliers prior to the January 1, 1980 commencement of the incremental pricing program, and they would be available on an ongoing basis after that for the benefit of firms which subsequently install No. 6 alternative fuel capability. The certification would only have to be filed once in order for a facility to qualify for a No. 6 ceiling price.

The proposed regulations required that owners retain any documents showing that a facility is equipped with No. 6 oil burning capability for a period of three years following the date a certification of alternative fuel capability is filed with the Commission. The type of proof which would fulfill this requirement, aside from the No. 6 oil burning equipment itself, would be, for example, bills for the actual installation of the equipment, a qualified engineer's report that No. 6 capability is in place or bills for purchases of No. 6 fuel oil. This retention of records would allow for the audit of filed certifications by Commission enforcement personnel. An affiant would be required to describe on his alternative fuel capability affidavit what he will retain as evidence for his claim that his facility is capable of burning a No. 6 oil.

The proposed rules required a natural gas supplier to have available for public inspection all alternative fuel capability affidavits he received. Additionally, all such affidavits filed with the Commission would be available to the public. Any interested person who desired to protest any certification of alternative fuel capability would be permitted to do so by filing a protest in accordance with section 1.10 of the Commission's Rules of Practice and Procedure.

Any industrial user which believes that the self-certification procedure imposes a special hardship on him would be permitted to request administrative relief under the adjustment procedures promulgated under subsection 502(c) of the NGPA.

In general, these certification procedures were supported by commenters. Several criticized various aspects of the procedures, however. Their comments and criticisms are considered below.

A. The Test for Alternative Fuel Capability

The proposed test for being able to certify to a No. 6 high or low sulfur oil burning capability was that the affiant's facility be "technically capable and legally permitted" to burn No. 6 high or low sulfur fuel oil, as the case may be. A number of parties objected that if the Commission insisted that there be an actual, installed capability to burn a No. 6 fuel oil, many facilities which could not burn No. 6 fuel oil would be induced to install the necessary equipment just in order to qualify for one of the No. 6 ceilings on incremental pricing, even though installing such equipment would be otherwise uneconomic and inefficient.

As a solution to this "induced installation" problem, several commenters proposed that the Commission abandon the three-tier approach and establish, instead, a single-tier No. 6 high sulfur ceiling. Others, however, suggested that the Commission solve the problem not by abandoning the three-tier approach but, instead, by abandoning the requirement that No. 6 oil burning equipment actually be installed for a facility to qualify for a No. 6 ceiling. Thus, they urged that the Commission permit companies to certify that they are "capable" of burning No. 6 fuel oil if they are "potentially capable", i.e., if they are merely capable of installing equipment which would permit them to burn No. 6 fuel oil.

The Commission rejects this suggestion. Obviously, any facility is capable of installing No. 6 oil burning equipment. If that were the test for being permitted to have a No. 6 ceiling, every facility would qualify for such a ceiling, regardless of whether or not No. 6 oil were actually its alternative fuel. The "potentially capable" test, then, is tantamount to being a proposal to have a uniform No. 6 ceiling rather than a three-tier approach.

Such a proposal should be considered directly and on the merits. The Commission does that not only herein but in a companion order issued today in this docket. As has been discussed above and as is discussed in the companion order, the Commission is very concerned about the three-tier approach giving rise to uneconomic investment in No. 6 fuel burning equipment. Accordingly, the Commission has transmitted to Congress an exemption rule which would hold the upper two tiers of the three-tier approach in abeyance until November 1, 1980.

The Wisconsin Public Service Commission commented that the words "technically capable" as used in the proposed regulation are ambiguous. They do not make it clear whether the equipment needed to burn No. 6 oil must be actually in place to qualify for a No. 6 ceiling or whether there only must be the potential to install the equipment. The Wisconsin Commission urged that the regulations be reworded to require that the No. 6 capability be actually installed. Additionally, the Wisconsin Commission urged that it be required that the equipment have been in place for three years for a facility to qualify for a No. 6 ceiling.

In response to the Wisconsin Commission's comment, the regulation shall be clarified so that it is clear that there must be an actual, installed capability to burn No. 6 fuel oil. The Commission will not require that such equipment have been in place for three years, however. To do so would have the result that facilities which had recently installed No. 6 capability would be incrementally priced at the No. 2 level. Since they have the capability to use No. 6 fuel oil, they would then be likely to switch to No. 6 oil and would be lost as contributors toward recovery of system costs.

B. Different Grades of Oil Used at the Same Industrial Facility

AGA commented that, at some facilities different grades of oil are used in different boilers. AGA suggested clarification concerning what could be certified as being the alternative fuel capability of such a facility. Both the regulations in the Notice of Proposed Rulemaking and the regulations adopted herein contemplate permitting users to certify on the basis of the lowest priced grade of oil they can burn at their industrial boiler fuel facility.

C. State Agency Certification of Alternative Fuel Capability

NARUC suggested having state agencies file certifications of alternative fuel capability in lieu of having industrial users filing the certifications. This, however, would be needlessly circuitous. The end-users would have to inform the state of the user's alternative fuel capability just so the state could communicate that information to the FERC. It is more direct to have the information filed with the FERC.

NARUC further suggested that, if the Commission determines to have certifications filed directly with the FERC, affiants should be required to file a copy with the relevant state Commission. The final regulations have been revised to accommodate this suggestion.

D. Public Inspection of Alternative Fuel Capability Affidavits

A large number of distributors objected to the requirement that customers' certifications of alternative fuel capability be available for public inspection at the distributor's office. Insofar as the certifications will be available to the public through the Commission's Office of Public Information, this requirement will be dropped.

A number of commenters suggested that the public be denied access to filed alternative fuel capability affidavits. This, however, would be of dubious legality and would effectively preclude the possibility of there being protests of industrial users' certifications of alternative fuel capability.

E. Protest Procedure

The Columbia Gas Distribution Companies suggested that the Commission provide a time limit for filing protests of certifications of alternative fuel capability. The Commission observes, however, that the protest procedures available to the public for purposes of protesting a certification are the procedures which are available under Section 1.10 of the Commission's regulations. Under that section, a protest is "intended solely to alert the Commission and the parties to a proceeding of the facts and nature of the protestant's objection. . . ." No sufficient reason has been advanced for putting a time limit on the period during which a party may bring to the Commission's attention a matter regarding a certification of alternative fuel capability. It would be contrary to the public interest to restrict the effectiveness of protests as an enforcement tool.

VII. Subsidiary Issues

There are several remaining issues regarding modification of the proposed regulations. First, AGA and several others suggested that the term "facility" be defined. The Commission shall so provide.

Secondly, several parties suggested that alternative fuel price ceilings be published less frequently than monthly. They expressed the view that less frequent publication would permit greater rate stability and would permit more data to be collected prior to the publication of a ceiling. The Commission, however, shall retain the requirement that ceilings be published on a monthly basis. Oil prices are so volatile that if there were longer publication period (e.g., quarterly or semiannually) there would be a danger that a ceiling would become either excessively low or high before the publication of the subsequent ceiling.

Lastly, several parties urged that the Commission adopt procedures by which an industrial facility could obtain a ceiling lower than that which would otherwise be applicable to that facility. It was suggested that the regulations provide that if an incrementally priced industrial customer could demonstrate that it would be able to purchase oil at a price below the applicable ceiling, that customer would not be incrementally priced above the level of the price at which it would be able to purchase the oil.

The Commission shall decline to adopt this proposed "failsafe" procedure. The Commission is concerned about a procedure which would depend upon gas customers obtaining prices from oil sellers not for the primary purpose of buying oil, but for the purpose of lowering gas rates. Further, the Commission observes that ceiling prices will be adjusted downward from the weighted average in a manner designed to ensure that the ceilings on incremental pricing will be below oil prices so as to prevent fuel switching. This obviates the need for the proposed "failsafe" procedure.

VIII. EIA Data Collection and Computation of Ceiling Prices

The Commission has requested the Energy Information Administration (EIA), the data collection agency of the Department of Energy,[20] to gather the data necessary to determine alternatvie fuel prices charged to industrial users in each region and to process that data in order to arrive at three ceiling levels for each incremental pricing region.

In the May 11, 1979 Notice of Proposed Rulemaking, it was proposed that each month data would be collected from fuel oil sellers regarding the prices they charge for No. 2 fuel oil, No. 6 high sulfur fuel oil and No. 6 low sulfur fuel oil. The price data would be for volumes delivered to large, non-utility industrial users which purchase on a large lot or contract basis. Price data would not include state or local sales taxes.

The May 11 Notice further proposed the method by which EIA would derive alternative fuel price ceilings from the data. For each region an average price, weighted by volumes, would be calculated for each of the three alternative fuels. Weighted average prices would then be adjusted downward by two standard deviations. For each region, the weighted average price for each fuel, as adjusted, would be compared to the lowest reported actual price for such fuel. The higher of these would be established as the alternative fuel price ceiling for that fuel for the region.

In its May 11 Notice, the Commission stated its belief that any lag between the collection of data and the publication of ceiling prices should be minimized. EIA had informed the Commission that the collection and analysis of data for any given month would require approximately 45 days processing time. Accordingly, the Commission requested that ceiling prices be available within 45 days after the close of the month for which data is collected, but not later than 15 days prior to the first day of the month for which the ceiling prices would be applicable. Thus, data collected for October, 1979 would have to be published in the form of ceiling prices by mid-December, 1979.[21] The ceiling prices would be published in the **Federal Register** and would be available through the FERC Office of Public Information.

Commenters raised a number of issues regarding the method of collecting oil price data and the generation of ceiling prices from that data. Those issues are discussed below.

Unlike the proposed regulations, the final regulations do not contain a description of the method to be followed by EIA in collecting data and generating ceiling prices. If the regulations were to tie EIA to a rigid procedure, EIA and the Commission would lack the flexibility to quickly adjust data collection and analysis techniques to accommodate any unforeseen problems as soon as they arise. Thus, data collection and analysis issues considered below are discussed not because they affect the final regulations, but because it has been the policy in this proceeding to keep the participants informed to the fullest extent possible about all aspects of the incremental pricing program. Accordingly, the following discussion is for informational purposes.

A. The Lag Between Collection of Data and Publication of Ceiling Prices

Many commenters stated that the major problem with the proposed procedures for EIA was the two month lag between the end of the month for which data would be collected and the beginning of the month for which ceiling prices would be effective.

The Commission requested comments on this potential lag problem in its Notice of Proposed Rulemaking, recognizing that prices for heavy oils usually decline in the summer months and escalate in the winter months. Under the proposed data collection procedures, April fuel oil prices would form the basis of ceilings for July. By then, however, industrial customers might be able to purchase fuel oil at a lower cost, in which case they would be likely to switch to oil.

The Commission requested comments on the extent to which there is a seasonality problem with the two month lag, and on whether any additional adjustments would be required or whether the proposed "two standard deviation" downward adjustment method would adequately compensate for the problem.

There was widespread agreement among the commenters that there is a serious problem with having ceiling prices based on data for oil sales made two months previously. There is not only a seasonality problem but also the more general problem that oil prices can fluctuate dramatically at any time of the year. OPEC cartel control of world oil prices has severely disrupted formerly well-established seasonal trends in oil prices. There can now be a substantial rise or drop in oil prices that is entirely unrelated to seasonality. Thus, it would be inaccurate to consider only earlier seasonal trends in developing an adjustment factor to compensate for the lag in publishing ceiling prices.

Commenters suggested a variety of solutions for the lag problem. Recognizing that some lag is inevitable using the data collection techniques described in the Notice of Proposed Rulemaking, several commenters suggested that those techniques be abandoned altogether and that posted oil prices be used instead. The problem with using posted oil prices, however, is that they are not consistently available for the various incremental pricing regions for all three grades of oil—No. 2, No. 6 high sulfur, and No. 6 low sulfur. More importantly, the data and methodology underlying posted prices are not subject to examination and verification by the Commission.

Another suggestion was to apply a flat percentage downward adjustment, e.g., 15 percent, after the "two standard deviation" adjustment methodology is applied to the weighted average oil prices derived from EIA's data. This, it was argued, would adequately adjust for the lag problem. Choice of a percentage adjustment factor would be arbitrary, however. Further, a flat percentage adjustment would sometimes lead to such a low incremental pricing ceiling that the benefits of incremental pricing to residential and commercial customers would be drastically reduced or even eliminated. Lastly, there could be no assurance that such an adjustment would in all cases adequately compensate for the lag problem.

A third suggestion was to retroactively adjust ceiling prices after the actual oil prices for a month are known. There would then be a further surcharge or refund depending on whether the retroactive adjustment was positive or negative. This, however, would lead to a constant and undesirable instability of rates.

A fourth suggestion was to have state agencies generate the ceilings. There is, however, no indication in the record that state or local authorities would not have the same lag problems EIA will have. Further, it is unclear that more than a handful of states would take on the task of generating timely data.

A fifth suggested solution was to use a point which was three standard deviations removed from the weighted average as the ceiling price. Such an approach, however, would lead to a ceiling price which would be lower than all but a tiny fraction of the oil prices observed during a month (about 0.13% in the case of perfectly normal distribution). Any skew to the right would lead to a situation in which the lowest price woud determine the ceiling price every time.

Another suggestion was to develop a mechanism which would use current oil price trends to adjust ceiling prices to reflect current market conditions. The Commission has used this concept in developing an adjustment mechanism to correct for lag.

The correction factor operates by tracking trends in oil prices derived from data not subject to the time lag. Each of the ceiling price data collected by EIA will be multiplied by the ratio of current posted oil prices to posted prices from two months previous. This correction factor is intended to be an estimate of *change* in prices (up or down) and not an accurate measure of what large industrial users are actually paying. Thus, it is not necessary that the quality of the data be as high as that of actual ceiling price data, and concerns regarding sample size and statistical validity are greatly reduced.

The prices (both current and those observed at the time of the ceiling price data collection) needed for the correction factor will be obtained by using posted prices. Use of EIA data or EIA publications is not possible because the data obtained from them would be subject to the same time lag problems as the uncorrected ceiling price data. In view of the ease with which posted prices may be obtained, they are clearly the best alternative.

Platt's Oilgram will be used as the source of posted price data. Comments suggested several publications of posted oil prices, but we believe Platt's Oilgram provides the most timely and geographically diverse information.

The prices found in Platt's Oilgram are given each trading day in the form of high and low prices for each oil product in each of the cities for which Platt's Oilgram publishes prices. The low price will be used for determining the correction factor. Furthermore, because there are not enough data available to compute separate correction factors for low sulfur residual fuel oil, correction factors will be computed for residual fuel oil without regard to sulfur content. This can be done since the correction factors are designed to reflect percentage changes in oil prices, not price levels themselves.

As for the number of correction factors which will be generated for residual fuel oil, the Commission has determined that it would not be possible to have a correction factor for each of the 79 incremental pricing regions, since posted prices for No. 6 fuel oil are unavailable for most of the regions. Instead, there will be two correction factors, one for the area west of the Rockies and another for the area east of the Rockies.[22]

The reason for having a separate correction factor for the West Coast is that it is a markedly distinct oil market area with separate sources of supply. Analysis of petroleum movement by the Congressional Research Service of the Library of Congress, as published by the U.S. Geological Survey, indicates that the West Coast is supplied from indigenous sources and from landings at West Coast ports. There is apparently little residual oil flow across the Rockies.

Additionally, oil price changes on the West Coast appear to move independently from the rest of the country. The Commission compared a series of posted prices for residual oil (2.8 percent sulfur maximum) in the New York City harbor area with comparable series (3.0 percent sulfur maximum) for the Los Angeles/San Francisco area. The two series covered 144 trading days, running from the last day of 1978 to

August 2, 1979. This interval includes the period of recent oil price increases as well as a seasonal shift from winter to spring. Analysis of these data [23] has led to the conclusion that trends in West Coast residual oil price changes are significantly different from those occurring on the East Coast.

The Commission has considered having separate correction factors for the Gulf Coast, the Rocky Mountain area and the Midwest. It was decided not to have a separate factor for the Gulf Coast because residual oil price trends in that area appear to be very similar to East Coast trends. Just as it compared a series of New York prices to West Coast prices, the Commission compared the same series of New York prices to a comparable series for the Gulf Coast area. Unlike West Coast No. 6 oil prices, Gulf Coast prices appear to move in tandem with prices on the East Coast.

It was determined that there should not be a separate correction factor for the Rocky Mountain area because posted prices are unavailable for it.

There will not be a separate correction factor for the Midwest because oil is supplied to that region largely from the Gulf Coast. Additionally, there are only four posted prices for the Midwest. These four do not move together as closely as would be expected if there were a unified Midwestern residual oil market.

Since a correction factor composed of the ratio of prices for only two days which are two months apart may not accurately reflect underlying trends, each of the two correction factors for residual oil prices will be based on the ratio of average posted prices for 10 recent days to average posted prices for the 10 days occurring two months previous. Use of 10 day averages rather than posted prices for a single day provides a more accurate measure of basic trends since averaging will smooth the irregular nature of oil price changes.

The Commission recognizes that inclusion of too many days in the moving average would dilute the more current observations with stale data, and the correction factor would fail to reflect the most recent developments. An examination of samples of price data led to a determination that 10 trading days (two weeks) of data is the optimum number of days to be included in the moving average in order to reduce the effects of aberrant prices without undue loss of currency.

Turning now to No. 2 oil, a separate correction factor will be calculated for each incremental pricing region. This is possible because posted prices for No. 2 oil are available for many more locations than are posted prices for residual fuel oil, especially in the West Coast and Rocky Mountain areas.

An attempt to divide the nation into several large regions similar to the two regions for the residual oil correction factor was unsuccessful. Distillate fuel oil, unlike residual oil, can be transported easily by pipeline, rail, and truck as well as by barge and tanker, the principal means of transporting No. 6 fuel oil. Thus, the national market for No. 2 fuel oil is unified to a considerable extent. However, while there are no significant differences in price trends among the large regions of the country, there are many smaller differences among individual cities and states.

Thus, the Commission has determined to develop a correction factor for each of the incremental pricing regions. Prices are posted for 19 of the 31 metropolitan incremental pricing regions.[24] For most of the remaining metropolitan regions, the factor computed for the state in which the metropolitan region is located can be used. If a metropolitan region overlaps state lines, the metropolitan area will be associated with the state in which the principal city of the metropolitan area is located. Thus, for example, the Cincinnati metropolitan area, which includes areas in Ohio, Kentucky and Indiana, will be associated with Ohio.

Two exceptions will be Region 2 (Hartford) and Region 28 (San Diego). The posted prices for New Haven and Los Angeles appear to be the most reasonable choices to use for developing correction factors for, respectively, Hartford and San Diego.

With regard to the states, Platt's Oilgram provides data for 32 cities which fall within a total of 27 states. In addition to those data, Platt's also lists posted prices for No. 2 fuel oil delivered to Midwestern terminals. Two other prices are listed for shipments in the South Central multistate region. Considering all of the data, prices are available for all but 14 of the contiguous 48 states. For those states without posted price data, values will be derived from the associated multistate region, taking into consideration all prices posted for that region.

The posted price data covers the multistate regions reasonably well, with three quotes for Region A (New England), five quotes for Region B (Mid-Atlantic), nine quotes for Region C (Southeastern), six quotes for Region E (Great Plains), five quotes for Region F (South Central), four quotes for Region G (Rocky Mountain) and four quotes for Region H (Pacific Coast). There were, however, only two quotes for Region D (Midwestern). The problem of there being so few observation points for Region D (Midwestern) can be alleviated by including, for correction factor purposes, the posted prices for Region 11 (Pittsburgh), Region 20 (St. Louis), and Region 22 (Minneapolis-St. Paul).

Finally, since many of the correction factors for No. 2 fuel oil will be computed from posted prices for only a single city, the moving average for computing the distillate fuel oil correction factors will be expanded to 15 trading days in order to minimize the effect of random aberrations due to short-term price changes.

B. Data To Be Collected

A number of issues were raised about the type of data which EIA should collect.

1. *Spot Market Data.* The proposed regulations indicated that only contract sales data would be collected by EIA. Cincinnati Gas & Electric Company supported this. A majority of the commenters which addressed the issue, however, urged that spot market data be collected as well.

In support of the argument that both spot market and contract data should be used by EIA, the commenters noted that it is no longer true that spot market prices tend to equal contract prices over the long-term, as stated in the Notice of Proposed Rulemaking. Further, PG&E stated that many of its gas customers which switched to fuel oil during the past few years did so on the basis of spot market, not contract, prices. PG&E observed that purchases on the spot market are made when the spot market price of fuel oil has fallen below the contract price of oil, and that there is a return to the use of gas when spot market prices exceed the contract price of oil.

INGAA stated that in some regions where the spot market is the dominant market for oil purchases, a failure to reflect spot purchases in ceiling prices could create a situation in which spot oil sales could undercut the incremental pricing ceiling. Natural Gas Pipeline Company of America (Natural) suggested that excluding spot market prices from the data collected by EIA may create an incentive for spot prices to be set lower than contract price in order to capture certain "swing" gas and oil loads.

In light of these and other, similar comments, the Commission finds that spot market oil prices should be collected by EIA in addition to contract market data.

2. *Transportation Costs.* In the Notice of Proposed Rulemaking it was proposed that transportation costs be included in the oil price data collected by EIA. Thus, the data would reflect the price charged for oil as delivered to the buyer's terminal. Nearly all commenters addressing this issue supported the proposed approach. AGA observed, "This approach ensures true comparability with the actual prices of potential alternate fuels in the market place. . . ."

The Michigan Public Service Commission urged, however, that transportation costs be excluded from collected oil price data because, given the large multistate regions proposed in the Notice of Proposed Rulemaking, transportation costs could vary markedly within a given region. In response, the Commission notes that transportation costs can be an important part of the delivered cost of oil. If transportation costs were not reflected in deriving ceiling prices, those ceilings would be unnecessarily low. In any event, however, the problem to which Michigan alludes is alleviated by the fact that ceilings will be published for states.

3. *Buyer or Seller Data.* In the Notice of Proposed Rulemaking, the Commission proposed that data would be collected from oil sellers rather than buyers. This approach was generally supported. However, several commenters urged that buyer data be used. They argued that fuel oil sellers would have an incentive to report higher than actual prices so as to permit them to undercut incrementally priced natural gas sales.

The Commission shall continue to request that EIA collect data from sellers. As explained in the Notice of Proposed Rulemaking, there are two reasons for taking this approach. First, the EIA currently collects data on No. 2 prices on a regular basis, and this collection effort can be adapted to the requirements of the incremental pricing program. Second, it is EIA's experience that collection of price data from end-users of a product is very difficult. If they do not respond voluntarily, enforcing compliance is a lengthy and burdensome task. These two reasons for collecting data from oil sellers continue to have validity.

As for the argument that sellers may have an incentive to misreport, EIA is alert to the potential problems inherent in there being a reporting burden which may be contrary to the respondent's interest. And in any event, the Commission notes that oil buyers as well as sellers may have an incentive to misreport the prices they are paying for fuel oil: if buyers report low prices, they may be able to lower their potential price for natural gas.

4. *Large Lot Sales Data.* No. 6 fuel oil is typically sold only to large customers in large quantities and is priced on such a basis. No. 2 fuel oil sold for boiler fuel use in large industrial facilities is also sold in large quantities and priced accordingly. Thus, since the first phase of the incremental pricing program involves large industrial boiler fuel facilities, it was proposed in the Notice of Proposed Rulemaking that alternative fuel price ceilings would be based on data reflecting large, bulk lot industrial sales.

In their comments, United Distribution Companies and Natural suggested that "large lot sales" be defined as those sales of amounts in excess of 6,000 gallons. They argued that is the normal size of a railroad tank car. The Commission shall, however, request that EIA collect data on sales in lots of over 4,000 gallons, the amount EIA has assumed it would use to determine what constitutes a "large lot" sale. If 6,000 gallons were the determinant, many full load truck deliveries would be excluded from EIA's data base.

C. The Derivation of Ceilings From Collected Data

1. *Averaging and Adjustments: The "Two Standard Deviation" Approach.* The proposed regulations provided that the weighted average prices determined by EIA would be adjusted downward by two standard deviations. The price which is two standard deviations removed from the mean would be the ceiling price for incremental pricing purposes, unless that price is lower than the lowest observed price for the respective grade of oil in the region. In that event, the lowest reported price would be the ceiling.

Most commenters who responded to the two standard deviation proposal were in favor of such an adjustment. Several commenters had alternative suggestions, however. AGA recommended that three standard deviations be used instead of two. As mentioned above, however, a point which is three standard deviations removed from the mean is so low that the lowest observed price would almost invariably determine the ceiling each month.

The Public Utilities Commission of Ohio and several others, in turn, suggested simply that the lowest observed price be used without there being any determination of a point which is either two or three standard deviations removed from the mean. The Commission shall not adopt an approach which would have the lowest observed price alone determining the ceiling, however. Use of the lowest observed price as the ceiling would not only lead to an erratic series of ceiling prices but would also leave open the distinct possibility of price manipulation.

The California Public Utilities Commission suggested an innovative alternative to the two standard deviation approach. Under the California method, all observed sales volumes would be ranked in ascending order by price. The point below which two and one half percent of the observed volumes occurred would then be determined. The sales price of the oil located at that point would then determine the incremental pricing ceiling. Thus, 97.5 percent of the observed oil sales volumes would have been sold at or above the derived ceiling price.

Should the oil price data be distributed in an approximately normal or "bell" shaped curve, the 97.5 percent approach would produce a result equivalent to that produced by the two standard deviation approach. But should the oil price data be distributed so that the curve is skewed to the right, as the Commission expects will occur most frequently, the two standard deviation approach would result in setting the ceiling price lower than it would be set under the 97.5 percent approach. However, in the event of a sharp skew to the left, the 97.5 percent approach could result in a lower ceiling.

Two principal arguments were advanced in favor of the 97.5 percent approach. First, it was said that the approach was simple, unambiguous and easy to execute. Secondly, no matter what the ultimate shape of the data distribution, the 97.5 percent approach would result in neither the possible exclusion of more than 2.5 percent of observed oil sales, nor a ceiling price set below the lowest reported price.

A closer examination of the 97.5 percent approach reveals a number of serious problems, however. For example, a single, low priced industrial sale could easily comprise the lowest priced two percent of the total volumes observed in a given region. This two percent would be ignored in setting the ceiling price by the 97.5 percent approach. Only the next one half percent would matter. But suppose, in a subsequent month, the large industrial purchased three percent of the total volumes observed. For that month, this single oil customer would determine the ceiling price. If the customer happened to purchase oil at an atypically low price, the resulting ceiling price would drop dramatically from the previous month. Thus, the 97.5 percent approach could lead to the ceiling fluctuating eratically, depending on slight changes in a single customer's consumption.

More importantly, since only the price of the lowest two and one half percent of observed volumes would be considered in determining a ceiling price, a single customer purchasing two and one half percent of the volumes could manipulate the ceiling prices. The Commission does not believe that such an unstable and potentially manipulatable ceiling price would be conducive to the smooth and proper operation of the incremental pricing program. The two standard deviation approach, by making full use of all reported data, would provide a more stable ceiling price and, most importantly, would substantially reduce the possibility of manipulation of ceiling prices.

Several commenters doubted the workability of the two standard deviation method. They expressed concern regarding the complexity of the mathematics of working with weighted data. All calculations will, however, be done by computer and thus the computational effort is not at issue.

A further argument was that the use of weighted data would produce mathematically invalid results in the derivation of a two standard deviation adjustment. However, concerns such as possible dependence among some of the data or a loss of degrees of freedom are misplaced. The results of the two standard deviation adjustment are valid for the purpose for which they shall be used. The downward adjustment by two standard deviations is designed merely to reflect the prices actually paid by industrial users of oil. The adjustment is not intended to serve as a statistical test. Nor is there any attempt to draw a statistical inference from the data. Accordingly, it shall be adopted.

2. *Conversion Factor.* Subsection 204(e) requires that alternative fuel price ceilings be stated on the basis of Btu's. The prices which EIA will collect will typically be on a per barrel basis. Thus, a conversion will be required. The EIA has utilized, over time, standard conversion factors of 5.8 million Btu's per barrel of No. 2 fuel oil and 6.3 million Btu's per barrel of No. 6 fuel oil in converting prices of various fuel to place them on a comparable basis. In the Notice of Proposed Rulemaking, the Commission stated that it anticipated that EIA would continue to utilize these factors.

AGA commented that there may be some variations in the Btu content of oil and urged that there be a downward adjustment factor to accommodate it. The Commission notes, however, that any need for such an adjustment factor will be substantially eliminated by the "two standard deviation lowest price" adjustment factor discussed above.

Other commenters urged that conversion factors be modified to reflect more than merely the Btu content of oil. The commenters pointed out that oil is more efficient to burn in a boiler than gas: it takes slightly more Btu's of natural gas than fuel oil to perform the same amount of work.[illegible] They urged that the conversion factors mentioned in the Notice of Proposed Rulemaking be modified to reflect the different combustion efficiences between oil and gas.

While gas may be slightly less efficient than oil, there are, on the other hand, a large number of reasons why a purchaser may prefer gas to oil. For example, gas burns cleanly, it does not require storage tanks and it is less destructive of refractory brick than is oil. To take into account efficiency without taking into account these other factors which may enter into a purchaser's decision would be one-sided. Yet, to develop a conversion factor which would adequately reflect all considerations affecting a purchaser's decision would be an impossible task.

Furthermore, such a conversion factor would be beyond the scope of subsection 204(e) of the NGPA. The ceiling is to be expressed in terms of "the price per million Btu's" for fuel oil.

There is no mention of adjusting the ceiling up or down to reflect efficiency ratios or other similar consideration that may affect a buyer's decision.

(Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, 15 U.S.C. 3301, *et seq.*)

In consideration of the foregoing, Subchapter I of Chapter I of Title 18 of the Code of Federal Regulations is amended in Part 282 by the addition of Subpart D as set forth below to be effective December 1, 1979.

By the Commission.

Lois D. Cashell,
Acting Secretary.

Appendix A

Note.—This appendix will not appear in the Code of Federal Regulations.

Federal Energy Regulatory Commission; Washington, D.C.

Alternative Fuel Capability Affidavit

[Docket No. RM79-21]

Participation is Voluntary. Copies of executed alternative fuel capability affidavits filed with the Commission shall be available through the Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426.

Please Read before Completing This Affidavit

Purpose

The Natural Gas Policy Act of 1978 (NGPA) requires the Federal Energy Regulatory Commission to determine the appropriate alternative fuel price to be used for establishing the price ceiling for certain categories of industrial boiler fuel sales of natural gas. Each nonexempt industrial boiler fuel facility, for purposes of determining the applicable alternative fuel price ceiling, will be deemed to have No. 2 fuel oil as its alternative fuel to natural gas unless it has certified its capability to burn No. 6 high sulfur fuel oil, No. 6 low sulfur fuel oil or No. 5 fuel oil under its boilers by filing this affidavit in compliance with the general instructions below.

Notice

If you do not complete and return this affidavit, the alternative fuel capability of your facility shall be deemed to be No. 2 fuel oil and the surcharge calculated under the incremental pricing program will be based on a No. 2 fuel oil ceiling price.

General Instructions

If alternative fuel capability for a non-exempt boiler fuel facility is claimed, this affidavit should be completed and signed, under oath, by a responsible official associated with the facility. A separate affidavit must be filed for each facility for which an alternative fuel capability other than No. 2 fuel oil is claimed.

The original and five copies of the affidavit should be submitted to: Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

Also, one copy must be submitted to your natural gas supplier. Additionally, each industrial facility shall retain such records, documents and data which formed the basis for the certification for a period of three years. Suitable records would include, for example, bills for the installation of the alternative fuel equipment, a qualified engineer's report that alternative fuel capability is in place and bills for purchases of No. 6 or No. 5 fuel oil.

If you have any questions concerning this affidavit contact Ms. Alice Fernandez on (202) 275-4406.

Definitions

(1) "Natural gas supplier" means an interstate pipeline or a local distribution company.

(2) "Local distribution company" means any person other than an interstate pipeline that receives gas directly or indirectly from an interstate pipeline and which is engaged in the sale of natural gas for resale or for ultimate consumption. A person is not considered as having received gas directly or indirectly from an interstate pipeline if the only service performed by an interstate pipeline for the purchaser is a transportation service.

(3) "Boiler fuel use" means the use of any fuel for the generation of steam or electricity.

(4) "Facility" means all buildings and equipment located at the same geographic site which are commonly considered to be part of one plant, mill, refinery or other industrial complex.

(5) "Industrial facility" means any facility engaged primarily in the extraction of processing of raw materials, or in the processing or changing of raw or unfinished material into another form or product.

(6) "Non-exempt industrial boiler fuel facility" means any industrial boiler fuel facility other than any such facility which has been exempted from the provisions of the incremental pricing program in accordance with Part 282 of the Commission's rules and regulations.

(7) "Alternative fuel capability" means installed capability to burn No. 6 fuel oil and to use it on a regular basis.

(8) "High sulfur fuel oil" means any oil containing more than one percent (1.0%) sulfur content by weight.

(9) "No. 2 fuel oil" means No. 2 oil as defined in the standard specification for fuel oils published by the American Society for Testing and Materials, ASTM D 396-78.

(10) "No. 5 fuel oil" means either light or heavy No. 5 oil as defined in the standard specification for fuel oils published by the American Society for Testing and Materials, ASTM D 396-78.

(11) "No. 6 fuel oil" means No. 6 oil as defined in the standard specification for fuel

oils published by the American Society for Testing and Materials, ASTM D 396–78.

(12) "Low sulfur fuel oil" means any oil containing one percent (1%) or less sulfur content by weight.

1. Name of company or organization:————.

2. Name of facility:————.

3. Address: Number——street———,city/town————,county————,
State———Zip Code——.

4. Name of natural gas supplier:————.

5. You may claim a price ceiling other than the price of No. 2 fuel oil if any non-exempt boiler within your facility has the capability to burn a No. 6 or No. 5 fuel oil as an alternative fuel and you check the appropriate box below.

(a) ☐ Has installed capability and is legally permitted to burn No. 6 low sulfur fuel oil.

(b) ☐ Has installed capability and is legally permitted to burn No. 6 high sulfur fuel oil.

(c) ☐ Has installed capability and is legally permitted to burn No. 5 fuel oil.

6.0 Description of records, documents and data substantiating the above claim: ————

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Dated: ——.
(Signature) ————————

Person Completing this Affidavit:
Name ————————————
Title ————————————
Phone No.————————————

Subscribed and sworn to before me this —— day of ———.
Notary Public ————————

Appendix B

Note.—This appendix will not appear in the Code of Federal Regulations.

Staff Analysis to Determine the Number of Correction Factors Needed In Generating a Residual Oil Correction Factor

The Commission's staff collected posted prices for residual oil based on the assumption that regional correction factors would be needed to reflect trends on the East Coast, West Coast, and Gulf of Mexico and in the Midwest. Having a correction factor for the Midwest was eliminated for the reason given in the body of this order.

On the West Coast, Platt's Oilgram reports a daily price for residual oil in the Los Angeles/San Francisco (LA/SF) area. On the East Coast, prices are reported for approximately 12 cities, although some prices are for residual oil with specified sulfur content. A price is quoted for the Gulf of Mexico area as well as specified price for New Orleans.

Staff considered the need for three separate regional correctional factors by comparing a series of posted prices for residual oil (2.8 percent sulfur maximum) in the New York City harbor with a similar series of data (3.0 percent sulfur maximum) for the LA/SF region and for the Gulf Coast region. The three series covered 144 trading days, running from the last of 1978 to the 2nd of August, 1979, the last day for which data were available. This interval included the period of recent oil price increases as well as a seasonal shift from winter to spring. In the first step of the analysis, staff found a high degree of correlation between the price series in New York and the other two regions.[1]

In a further analysis, staff considered the daily differences between the New York series and the other two series. The concern was not with the average difference between prices in one region and those in another, but with the variation in the series of differences. Little variation would indicate that price trends in two regions were similar and that separate correction factors would be unnecessary.

For the interval studied, the analysis indicated an average price difference of $1.43 per barrel between New York and the LA/SF region, with New York prices being higher.

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[1] The correlation coefficients were 0.971 between New York and LA/SF, and 0.975 between New York and the Gulf region. A high degree of correlation was not unexpected since time series data were being compared, and each series is strongly influenced by the overall worldwide trend in rising oil prices. Moreover, unlike many cross sectional data, these time series are highly autocorrelated in that the price on any given day is influenced by the price on the preceding day. Thus each day's price is not a truly independent observation. In spite of these statistical considerations, the extremely high correlation between the New York and Gulf series indicates the likelihood of close coupling between oil price levels in these regions.

The standard deviation was 1.34, signifying a good probability that prices in LA/SF would fall between $0.09 and $2.77 less than prices in New York. This level of dispersion is too large to ignore. It indicates that the East and West Coast residual oil markets do not operate with a dependable degree of consonance. Thus, a single correction factor would be inappropriate for both regions.

The series of price data for the New York region and for the Gulf region displayed a more harmonious relationship. The average price difference was $1.98 per barrel, reflecting lower prices in the Gulf region, but, the standard deviation was only 0.49. This result is in accord with the high correlation between New York and Gulf region prices as well as with the fact that East Coast and Gulf region oil markets are linked by extensive trade.[2]

In a final analysis, the entire series of price data for the Gulf region was regressed on the New York data in order to learn more about the relationship between the two data sets.[3] As a result of the analyses, a separate correction factor for the Gulf region appears unnecessary.

—Footnotes—

[1] *Regulations Implementing the Alternative Fuel Price Ceilings on Incremental Pricing Under the Natural Gas Policy Act of 1978*, "Rule Exempting Industrial Boiler Fuel Facilities from Incremental Pricing Above the Price of No. 6 Fuel Oil", Docket No. RM79-21, issued September 28, 1979.

[2] *Regulations Implementing the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978*, "Final Rule", Docket No. RM79-14, issued September 28, 1979.

[3] S. Rep. No. 95-1752, 95th Cong., 2nd Sess. 100 (1978).

[4] The following data were submitted by the South Carolina Public Service Commission:

The provisions of the NGPA and the proposed regulations in Docket No. RM79-21 will potentially affect twenty-four (24) industrial customers of the jurisdictional subsidiaries of Carolina Energies, Inc. Those subsidiaries are Carolina Pipeline Company, Inc., and Carolina Natural Gas Corporation. In accordance with approved curtailment plans and based on current supplies of natural gas, those customers are entitled to a total of 60,929 Mcfd. Eighteen (18) of those customers use No. 6 (high sulfur) fuel oil as their alternate fuel. They account for sixty-four percent (64%) of the daily entitlement.

Seventeen (17) industrial customers of South Carolina Electric and Gas Company may be affected by the provisions of the NGPA and the proposed regulations. Those customers are entitled to a total volume of 21,593 Mcfd. Nine (9) of those customers utilize No. 6 (high sulfur) fuel oil as an alternate fuel, and those customers account for eighty-four percent (84%) of the daily entitlement.

Two (2) industrial customers of United Cities Gas Company may be affected by the NGPA and the proposed regulations. The total entitlement of those customers is 2,529 Mcfd. One of those customers uses sixty percent (60%) of the total entitlement and utilies No. 6 (high sulfur) fuel oil as its alternate fuel.

Three (3) industrial customers of Peoples Natural Gas Company of South Carolina may be affected by the provisions of the NGPA and the proposed regulations. Those customers are entitled to 3,337 Mcfd. Since their alternate fuel is No. 6 (high sulfur) fuel oil, the total entitlement would be affected by the NGPA and the proposed regulations.

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[2] Perspective on the significance of the dispersion in price differences may be gained by looking at the average price change for both the New York and Gulf regions. In New York, the average price change, in either direction, was $0.38 per barrel. In the Gulf region, the average change was approximately the same at $0.41 per barrel. This suggests that much of the dispersion in the differences in prices is due to the size of the price changes themselves, as they occur more or less randomly, rather than to any underlying difference in market behavior. Of course, this observation is of heuristic value only. Further analysis is needed to establish such a conclusion.

[3] $P = 0.900 + 0.929\ P_{Gulf} + e_t,\ R^2 = 0.951$ NY (0.0793) (0.0177)

The high value of R^2 indicates an overall extremely good fit—the regression line accounts for most of the observed variation in the Gulf prices. Of equal importance for our purpose is the value of the slope, (0.929). Were this parameter found equal to unity, a change in the New York price would, on average, produce an identical corresponding change in Gulf prices. Thus, an additive correction factor would be accurate. In fact, over the time period studied, the estimated slope is found to be slightly less than unity. Although the departure from unity is statistically significant (as evidenced by the very low standard error of the estimated slope), the practical effect is negligible. Not only did the period under study encompass an atypically large surge in oil prices but the multiplicative nature of the proposed correction factor provides for closer agreement.

An example may prove to be helpful. Over the period studied, New York prices averaged $15.246 per barrel. Gulf area prices averaged $13.262 per barrel, 13 percent less. Imagine that, during the time lag between ceiling price data collection and publication, New York prices were observed to rise 5% (a very high annual growth rate of 34% assuming a two month lag). A correction factor of 1.05 would be applied to all prices, bringing the Gulf area to $13.925. Ignoring random errors, the regression indicates that the $0.762 increase in New York translates into a (0.929 x $0.762) = $0.708 increase in the Gulf area. The "true" increase would bring the Gulf price to 13.970. Thus, the correction factor would in fact undercorrect by 4.5 cents per barrel or about 7 mills per MMBtu. This is negligible.

[5] Consumers Power estimated that 22.3 Bcf of gas sold on its system will be subject to incremental pricing. This gas is sold to 47 industrial boiler fuel customers, thirty of which have the capability to burn No. 6 fuel oil. Those 30 customers, however, purchase 20.2 (91%) of the 22.3 Bcf of gas which will be subject to incremental pricing.

[6] Northern Natural Gas Company, in comments filed prior to the Notice of Proposed Rulemaking, said there are approximately 60 customers on its system which will be subject to the first phase of the incremental pricing program. Northern Natural estimated that these customers will, in 1980, use approximately 3.5% of the volume of natural gas sold by Northern. Northern found through discussions with its customers that for approximately one-half of the gas volumes consumed by the large industrial users, No. 6 fuel oil is the alternative fuel. Thus, Northern anticipates that there would be a substantial loss of industrial sales if the alternative fuel price ceiling remained at the No. 2 level.

[7] Public Service Electric and Gas Company commented that it had 27 industrial boiler fuel customers which consumed 32,241 Mcf per day. Of that, 28,241 (88%) was consumed by the 20 customers which had the capability to burn No. 4 or No. 6 fuel oil:

Lowest Price Alternate Fuel	No. of Customers	Mcf Per Day
#2	7	4,000
#4	6	3,991
#6	14	24,250

[8] In its May 11, 1979 Notice of Proposed Rulemaking, the Commission stated at page 13 (mimeo ed.) (44 FR 29090, 29093 [May 18, 1979]):

> In addition to the comments, the Commission has available to it data obtained by the Energy Information Administration (EIA). In December 1978, the Energy Information Administration of DOE sent a questionnaire, Form EIA-134, to interstate pipelines, local distribution companies, state commissions and other interested persons to gather information, on a voluntary basis, about the alternative fuel capabilities of both large and small industrial boilers. EIA also solicited opinions as to what the ceiling should be. The Commission has examined the results of this survey, bearing in mind that the responses were voluntary and thus do not constitute a statistically valid sample. The survey indicated that a significant number of boiler fuel facilities in a majority of the states are equipped to burn No. 6 fuel oil. Further, the majority of respondents favored a ceiling based on the No. 6 oil price. However, the survey also indicated that there are a number of boiler fuel facilities which will be subject to the first phase of the incremental pricing program that only have an alternative fuel capability to use No. 2 fuel oil.
>
> The Commission has also analyzed the data reported on the EIA-50 form. EIA-50 is used to gather information on the alternative fuels that are used to offset curtailments in the delivery of natural gas. Analysis indicates that during the period April 1977–March 1978, large industrial users utilized No. 5 or No. 6 fuel oil to offset approximately 40 percent of the natural gas curtailment they experienced. This percentage translates to approximately 64 million barrels of oil. The EIA-50 data also indicate that No. 1 or No. 2 fuel oil was utilized to offset approximately 20 percent of natural gas curtailments during the same period.

[9] The 741 Bcf figure represents the load loss which AGA says would result from a No. 2 ceiling if ceiling price levels were determined for small incremental pricing regions such as SMSA's. The 788 Bcf figure represents what the load loss would be under a No. 2 ceiling if large regions such as states were used.

[10] In order to determine the total amount of incremental costs which would be absorbed by industrial customers under the two scenarios, AGA assumed that the average price of gas charged to industrial users would be $2.35/MMBtu before the addition of any incremental pricing surcharges. AGA assumed that No. 2 fuel oil would sell for $4.10/MMBtu in 1981. Thus, the average maximum surcharge absorption capability of incrementally priced customers under a No. 2 "High Cap" ceiling would be $1.75/MMBtu. AGA further assumed that low sulfur (0.3%) No. 6 fuel oil would sell for $3.50/MMBtu, and that under a low sulfur No. 6 "Low Cap" ceiling all incrementally priced industrial facilities would be surcharged to the full extent of their surcharge absorption capability. By multiplying the amount of gas to be incrementally priced under each scenario by the amount of the surcharge, AGA determined that, even though the low sulfur No. 6 "Low Cap" ceiling was 60 cents less than the No. 2 "High Cap" ceiling, the increase in volumes available to be surcharged under a low sulfur No. 6 ceiling resulted in there being a total "Low Cap" surcharge recovery of $2.07 billion, $495 million more than the $1.575 billion AGA estimated would be recovered if there were a No. 2 ceiling. The $495 million difference would be spread over all other customers, with the result that gas prices to high-priority customers would be 5 cents/MMBtu higher under the High Cap Scenario than under the Low Cap Scenario.

[11] For purposes of its study, DOE used $3.80 per MMBtu as the price for No. 2 fuel oil in May, 1979. For high sulfur No. 6 fuel oil, DOE averaged prices for No. 6 oils with sulfur contents of 1.0% and above to derive an average price of $2.60 per MMBtu.

[12] DOE projected the June, 1979 price of No. 2 fuel oil to be $4.20 per MMBtu. The average price of No. 6 high sulfur fuel oil was projected to be $3.40 per MMBtu.

[13] Indeed, the price differential between high sulfur No. 6 fuel oil and low sulfur No. 6 oil can be as great as that between No. 2 fuel oil and low sulfur No. 6 oil. Generally, low sulfur No. 6 fuel oil is used only in facilities which are not permitted to burn high sulfur No. 6 fuel oil due to air quality standards.

[14] AGA projected that the price of No. 2 fuel oil would be $4.10 in 1981 and that the price of No. 6

would be $3.50. Thus, each industrial customer would contribute $1.75/MMBtu if there were a No. 2 ceiling and $1.15/MMBtu if there were a No. 6 ceiling.

[15] In its study, DOE assumed that the cost of providing gas to industrial customers is the cost incurred during off-peak summer periods (the acquisition cost plus variable transportation and processing costs and taxes). When gas is supplied during the winter, the marginal cost of gas may increase significantly, especially if the additional gas is delivered from underground storage, liquified natural gas storage, synthetic natural gas plants, or other peak-shaving facilities. Thus, even DOE's study, insofar as it reflected the off-peak marginal cost of gas and not the peak marginal cost, understated the benefit to high priority customers of shedding industrial load during peak periods.

[16] To illustrate, for 1981, the year used in the AGA study, DOE would subtract $2.60 (a wellhead price of $2.34 plus allowances for processing, transportation and gross receipts tax), not AGA's average retail industrial rate of $2.35, from the projected No. 2 and No. 6 ceiling prices in order to derive the per MMBtu contribution of industrial customers to system costs. The effect would be to reduce the per MMBtu contribution that would be made by industrials. Thus, under DOE's approach, more load loss would have to result from a No. 2 ceiling to warrant using a No. 6 rather than No. 2 ceiling.

[17] DOE observed that these results suggest that the biggest effect on residential and commercial rates comes from having incremental pricing in place, and that the differences in rates resulting from using different ceilings are relatively small compared to the rate reduction which will result just from having incremental pricing.

[18] In its study DOE used $2.51 as the marginal of gas for May and June, 1979. The price of high sulfur No. 6 fuel oil, based on a projected June, 1979 world oil price of $19.60, was $3.40, a difference of 89 cents from the marginal cost of gas. (The May, 1979 price of high sulfur No. 6 fuel oil, however, was $2.60, resulting in a nine cents difference. This, again, illustrates the impact a change in world oil prices can have.)

[19] A copy of the alternative fuel capability affidavit, as revised to reflect the final regulations adopted in this order, is appended hereto as Appendix A.

[20] Section 506(b) of the NGPA vests in the Commission, for purposes of carrying out the functions vested in it by the NGPA, all of the authority vested in the Secretary of Energy by section 301(a) of the DOE Organization Act, which encompasses the authority set forth in section 11(b) of the Energy Supply and Environmental Coordination Act of 1974 and section 13 (b), (c) and (d) of the Federal Energy Administration Act of 1974. This authority will be exercised by the EIA on behalf of the Commission.

[21] EIA has consulted with potential respondents to Form EIA 194, the form which EIA currently proposes to use to gather data for purposes of establishing incremental pricing ceilings. The potential respondents told EIA that they would need more time to complete the form than EIA had allowed when EIA made its original estimate that 45 days would be required for the collection and analysis of data for any given month.

Accordingly, five more days will be allowed for collection and analysis of data so that respondents can have an additional five days to return Form EIA–194. The final regulations will require that alternative fuel price ceilings shall be published on the 20th of each month, not the 15th, so that 50 rather 45 days will be permitted for collection and analysis of data for each month.

[22] The Western correction factor will apply to six metropolitan regions. Phoenix (Region 26), Los Angeles (Region 27), San Diego (Region 28), Seattle–Takoma (Region 29), Portland (Region 30), and San Francisco (Region 31), and it will apply to the states of Arizona, California, Nevada, Oregon and Washington.

[23] Appendix B contains an analysis of this data series.

[24] Regions 1, 3, 4, 5, 7, 9, 11, 12, 17, 19, 20, 21, 22, 25, 26, 27, 29, 30, and 31.

[25] Pacific Gas and Electric Company (PG&E) explained that this burning efficiency differential arises from the chemical composition of the two fuels. Fuel oil contains relatively less hydrogen than does natural gas. Upon combustion, fuel oil loses relatively less useful heat through the formation of water vapor. Consequently, it is slightly more efficient with respect to the amount of useful work that can be derived.

[¶ 30,086A]

44 F. R. 57778 (October 5, 1979)

18 CFR Part 282

[Docket No. RM79–21; Order No. 51]

Rule Exempting Industrial Boiler Fuel Facilities From Incremental Pricing Above the Price of No. 6 Fuel Oil

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule, subject to congressional review.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts a rule which, if not disapproved by either House of Congress, will amend the regulations which set ceilings on the prices which can be charged under the incremental pricing program to large

industrial facilities for the natural gas they burn as a boiler fuel. Under this exemptive rule, these large industrial users would be charged a price for their natural gas usage equivalent to the price they would pay for high-sulfur residual fuel oil. This rule will be effective until October 31, 1980.

EFFECTIVE DATE: December 1, 1979, if not disapproved by a Congressional Resolution of Disapproval.

FOR FURTHER INFORMATION CONTACT:

Norman A. Pedersen, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8377.

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Regulations Implementing Alternative Fuel Price Ceilings in Incremental Pricing Under the Natural Gas Policy Act of 1978.

Rule Exempting Industrial Boiler Fuel Facilities From Incremental Pricing Above the Price of No. 6 Fuel Oil

Issued September 28, 1979.

Section 201 of the Natural Gas Policy Act of 1978 (NGPA) (Pub. L. 95-621) requires that the gas used in certain industrial boiler fuel facilities shall be subject to incremental pricing by means of certain surcharges. Section 204 provides, however, that such surcharges may not cause the rates charged for natural gas to incrementally priced industrial facilities to rise above the appropriate alternative fuel price. By this order, under authority of subsection 206(d) of the NGPA, the Commission approves and transmits to Congress a rule affecting the applicable alternative fuel price or ceiling. The rule provides that, until November 1, 1980, each applicable industrial boiler fuel facility shall be exempt from incremental pricing above the level of the price of No. 6 high sulfur fuel oil in the incremental pricing region in which such facility is located.

In a companion "Final Rule" issued today in this docket,[1] the Commission has promulgated a three part ceiling system (three-tier approach). Depending upon a facility's installed capability and legal authority to use certain fuels, an incrementally priced facility would have its ceiling price for natural gas set at the level of the appropriate regional price of No. 2, low sulfur No. 6 or high sulfur No. 6 fuel oil. The Commission found that such a system best met the Congressional purpose embodied in Title II of the NGPA.

However, the Commission also concluded that this system may result in significant investment by facilities in order to install No. 6 capability to gain the advantage of a lower ceiling price for natural gas. The amount of this induced investment cannot be estimated with precision at this time, but the record indicates it could be a sizeable amount. More importantly, the public benefits, if any, that would result from a significant amount of the nation's capital being devoted to this purpose remains unclear. Thus, the Commission is extremely concerned about the three-tier approach becoming effective without more time to gain familiarity with the incremental pricing program, the incrementally priced industrial facilities, and the extent to which the three-tier approach would be likely to result in an inducement to install otherwise unneeded No. 6 oil burning equipment. Therefore, the Commission believes it would be in the public interest to hold the upper two tiers of the system in abeyance for 10 months—from January through October, 1980—to provide a period during which a better understanding of the implications of the three-tier approach can be obtained.

Additionally, implementation of the incremental pricing program would be eased if, at the outset, there were a single rather than a three-tier price ceiling. The Energy Information Administration has encountered difficulties in putting into place the data collection and analysis system which will be necessary under the three-tier approach. The 10 month exemption will ease EIA's task.

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[1] *Regulations Implementing the Alternative Fuel Price Ceilings on Incremental Pricing Under the Natural Gas Policy Act of 1978*, "Final Rule", Docket No. RM79-21, issued September 28, 1979.

The Commission, however, is of the opinion that to provide for a single No. 6 ceiling until November 1, 1980 under authority of section 204(e) may go beyond the Commission's statutory role in implementing section 204. Consequently, it is issuing this exemptive rule which will go to Congress for its review pursuant to section 206 of the NGPA.

This rule is subject to Congressional review and may be disapproved by either House of Congress. The rule will take effect December 1, 1979 unless, during the first 30 days of continuous session of Congress after a copy of the rule has been submitted to each House of Congress, either House adopts a resolution of disapproval. If, however, Congress permits the exemption embodied in this rule to take effect, the rule shall hold in abeyance until November 1, 1980 so much of the three-tier regulations as are inconsistent with having a high sulfur No. 6 ceiling.

The exemption which this order implements will expire on October 31, 1980. On November 1, 1980 the three-tier approach adopted in the companion Final Rule in this docket will become fully effective, unless that rule is amended in the interim or a further exemption rule is transmitted to Congress and not disapproved.

I. Background

Subsection 204(e) of the NGPA provides that the "appropriate alternative fuel cost" for an industrial facility shall be the price paid for No. 2 fuel oil in the region in which the facility is located. The Commission is authorized, however, under certain circumstances, to reduce the ceiling to a level not lower than the price of No. 6 fuel oil.

Sec. 204 Method of Passthrough

* * * * *

(e) Determination of Alternative Fuel Cost.—

(1) In General.—Except as provided in paragraph (2), the appropriate alternative fuel cost for any region (as designated by the Commission) shall be the price, per million Btu's, for Number 2 fuel oil determined by the Commission to be paid in such region by industrial users of such fuel.

(2) Reduction of Appropriate Alternative Fuel Cost Allowed.—The Commission may, by rule or order, reduce the appropriate alternative fuel cost—

(A) for any category of incrementally priced industrial facilities, subject to the rule required under section 201 (including any amendment under section 202 to such rule) located within any region and served by the same interstate pipeline; or

(B) for any specific incrementally priced industrial facility which is subject to such requirements and which is located in any region;

to an amount not lower than the price, per million Btu's for Number 6 fuel oil determined by the Commission to be paid in such region by industrial users of such fuel, if and to the extent the Commission determines, after an opportunity for written and oral presentation of views, data, and arguments, that such reduction is necessary to prevent increases in the rates and charges to residential, small commercial, and other high-priority users of natural gas which would result from a reallocation of costs caused by the conversion of such industrial facility or facilities from natural gas to other fuels, which conversion is likely to occur if the level of the appropriate alternative fuel cost were not so reduced.

The legislation provides, in sum, that, if keeping the incremental pricing ceiling at the level of No. 2 fuel oil would be likely to result in fuel switching and a shifting of capital costs so as to increase residential and commercial rates, the Commission may act under authority of subsection 204(e) to reduce the ceiling as necessary, but not lower than the price of No. 6 fuel oil, to prevent incremental pricing from having such a detrimental effect. Although the Commission is authorized to reduce the ceiling so as to minimize the likelihood of fuel switching and its adverse consequences, the Commission believes that subsection 204(e) implies that Congress did not intend that the ceiling be reduced below a point where residential and commercial rates would be higher than they would have been with a No. 2 ceiling.

II. The Commission's Three-Tier Rule

In the Final Rule issued today in this docket, the Commission found that the record shows that a ceiling set at the price of No. 2 fuel oil would result in substantial industrial load loss, though precise quantification is impossible.

On the other hand, it is not clear that high priority consumers would be benefitted by having a single ceiling set at the No. 6 rather than the No. 2 level. Despite some data and arguments that would support a single No. 6 ceiling, an analysis by the Department of Energy and other information seems to indicate that, in some cases, a balancing of induced load losses with the amount of the surcharge passed through to industrial consumers favors a No. 2 ceiling relative to a No. 6 ceiling.

Put differently, the record is clear that in order to carry out the Congressional intent to protect the interests of high priority consumers from *likely* adverse impacts, the Commission must exercise its statutory authority to choose an incremental pricing ceiling other than the price of No. 2 fuel oil. There is, however, a high degree of quantitative uncertainty about the impacts of a ceiling set at the price of No. 6 fuel oil.

In response to this uncertainty, the Commission has developed a system of multiple ceilings. The objective of this system is to maximize recovery of incremental costs from each incrementally priced industrial facility, and at the same time minimize the likelihood that any such facility would switch to an alternative fuel. To this end, the Commission has provided in the Final Rule issued in this docket that three ceilings be established for each region of the country—one at the level of No. 2 fuel oil, another at the level of low sulfur No. 6 fuel oil, and a third at the level of high sulfur No. 6 fuel oil.

An incrementally priced industrial facility would pay a price for natural gas which would include a surcharge determined by the level of the lowest priced type of fuel oil it had the installed capability and the legal authority to use.

A three-tier approach would avoid the establishment of a blanket ceiling for all users. Such a ceiling might be too high for some, resulting in their loss to the system. At the same time, a single ceiling might be too low for others, allowing them to escape some of the costs that Congress intended them to bear under the incremental pricing program. By differentiating among incrementally priced facilities on the basis of fuel burning capability and lawful authority, the three-tier approach would maximize the flow-through of incremental costs to industrial gas customers.

Despite the theoretical attractiveness of the three-tier system, however, and despite the Commission's view that it best meets the statutory mandate contained in Title II, the Commission is concerned about the public interest implications of implementing this system immediately. The major concern stems from the possibility that the three-tier system will lead to significant amounts of investment to install equipment to burn high sulfur No. 6 fuel oil.

III. The Induced Investment Issue

The record in this docket contains considerable discussion and some quantitative data about the amount of investment that would be likely to result as a consequence of the three-tier system. As the record shows, many facilities that could install No. 6 fuel burning capability have not done so in the past because gas has generally been available and curtailment periods have been short. Such firms find it economic and convenient to use No. 2 rather than No. 6 fuel oil as a substitute for gas during their short periods of curtailment. However, if gas for such firms were priced at the No. 2 oil ceiling, these same facilities would find it economically advantageous to install No. 6 capability. As the Department of Energy (DOE) noted:

> Firms * * * may find a residual backup system very attractive economically. While, before, the backup system was being utilized only a small percent of the year, now the

backup system is reaping lower fuel prices year round.

There are a number of elements that distinguish a residual oil burning boiler from a distillate oil burning boiler.[2] In order to render a gas-fired boiler physically capable of burning residual oil, the minimum investment a firm would have to make would involve modifying the burners, adding a steam or mechanical atomizer, and adding an insulated storage tank.[3] DOE estimated that an industrial facility could install residual oil firing capability with a minimum investiment of $50,000 to $90,000, depending on what modifications were made to the fuel handling system.[4] Southern California Gas Company, on the other hand, estimated the cost at a relatively modest $29,500 to $65,000 for a 500 horsepower boiler. Although there is some uncertainty about the cost, there is no evidence that the required investment would be large.

Expressed in terms of the cost per MMBtu, the relatively small investment in No. 6 oil burning equipment is very attractive when compared with the savings that would be enjoyed if an end-user thereby became legally able to purchase gas at the price of No. 6 fuel oil. DOE put the cost of installing residual oil capability at 16 to 39 cents per MMBtu, depending on the boiler firing rate. DOE also estimated that the savings in lower gas prices would be between 60 cents (if the end-user qualified for a No. 6 low sulfur ceiling) and $1.20 (if the end-user qualified for a high sulfur No. 6 ceiling.)

Many participants in this proceeding provided specific illustrations of the economic desirability of installing No. 6 capability. For example, the National Aeronautics and Space Administration (NASA) said: "Installation of that capability would be cost effective for at least three NASA field installations and would represent a 40 percent dollar savings over the total anticipated surcharges." Southern California Gas Company and the American Gas Association (AGA) estimated that the capital costs of installing No. 6 capability would usually be fully recovered within a year's time.[5]

Chairman Katherine E. Sasseville of the Minnesota Public Service Commission stated that the price of No. 2 fule oil in Minnesota typically exceeded the price of No. 6 by more than $1.00 per MMBtu. Under the three-tier approach the user of 300 MMBtu of natural gas a day who has No. 2 alternative fuel capability would be charged at least $300 a day more for natural gas than if he qualified for a high sulfur No. 6 ceiling. If he burned gas 300 days a year, in one year he would pay $90,000 more for his gas. The present value of that yearly cost over 20 years discounted at 10 percent exceeds $750,000. Thus, Chairman Sasseville concluded that such a Minnesota customer would find it cost effective to install the capability to burn No. 6 if that could be done for $750,000 or less. And the record shows it could be. Using the DOE estimate of $90,000 as the cost to install No. 6 capability, Chairman Sasseville's figures imply that the investment could be recovered in one year, even ignoring the tax savings generated by the new investment.

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[2] For example, in order to burn oil grades heavier than No. 2 or No. 4, steam or electric heaters are necessary to raise the temperature, and heavier fuel pumps are needed to transport the fuel. Due to the burning and contamination characteristics of residual oil, high quality refractory brick is required in residual oil burners. (If residual oil were fired in a distillate boiler, severe deterioration of the refractory wall would take place.) In addition, soot blowers are needed to dislodge ash accumulation, and heat exchanging tubes must be replaced if a boiler is retrofitted to have a No. 6 fuel oil firing capability. A steam/air or mechanical atomizer is also needed, as is increased air blower capacity.

[3] Other items such as installation of a sootblower, refractory upgrade, or tube modification are necessary only if No. 6 oil is to be burned for a prolonged period.

[4] In order to have the capability to burn residual oil for a prolonged period of time (e.g., over a week) without excess furnace wear would require an additional $154,000, DOE estimated. Stringent environmental controls would require a much greater investment.

[5] The Southern California Gas Company assumed a $1.00 difference between the price of No. 2 fuel oil and the price of low sulfur No. 6. At the time Southern California Gas filed in this docket, it said the cost of No. 2 fuel oil in California was $4.30 / MMBtu and the cost of low sulfur No. 6 oil (0.5 percent sulfur content) was $3.30/MMBtu.

Given the economics that could be realized under a three-tier approach as a consequence of installing the capability to burn No. 6 fuel oil, the record is clear that many firms that currently use No. 2 fuel oil as backup would switch to No. 6. Nationally, however, the precise number that would be able to convert, taking into account economics, environmental laws, and other pertinent considerations, remains unclear at this time despite the efforts of the Commission and participants in this proceeding to provide data for the record.

The present record on precisely how many facilities would be induced to invest in No. 6 capability consists mainly of system-specific examples. To illustrate, DOE provided a study of Wisconsin Gas Company's industrial gas users that may be incrementally priced. The study indicated that there are a significant number of gas boilers in Wisconsin for which distillate oil is used as a backup. Currently, 49 percent of the gas sold to incrementally priced facilities in Wisconsin is consumed at facilities for which No. 2 oil is the alternative fuel. This accounts for 12.4 Bcf of annual consumption. DOE concluded that the users of 8.7 Bcf (70 percent) would install residual fuel backup capability in order to qualify for lower gas prices.

DOE estimated that in the Wisconsin Gas Company service area alone, the total capital investment required for equipment to convert from distillate to residual oil backup capability would be $19.6 million. As for the total nationwide cost of these conversions to No. 6 capability, DOE said that, as an upper bound estimate, between $300 and $400 million would be expended.[6]

In short, the potential for conversions from a No. 2 fuel oil backup capability to a No. 6 capability would be widespread, and, though individual firms could recover the cost relatively quickly, the aggregate national cost could be large. The issue is whether there would be any benefits associated with this national expenditure. It can be argued that there may be an offsetting public benefit in having facilities with the option to burn residual fuel oil as well as natural gas and distillate at a time when there is always a possibility of any one of a variety of unanticipated fuel crises occurring.

There is further concern. As discussed at length in the preamble to the companion three-tier rule in this docket, the record shows that a substantial portion of industrial boiler fuel load already has the capability to burn No. 6 fuel oil. If, in response to the three-tier ceiling, there is widespread conversion from No. 2 to No. 6 backup capability, the remaining amount of industrial boiler fuel load which would be eligible to be incrementally priced at the No. 2 level could be reduced to a *de minimis* amount. In such a situation, the surcharge absorption capability captured by having the three-tier approach rather than a single No. 6 ceiling would be sharply reduced. The reduction could be significant enough that the benefits of a three-tier approach to residential and commerical customers would not be substantially greater then they would be if there were a single No. 6 high sulfur ceiling. This possibility raises a troublesome question about the need for the regulatory and data-support system required to implement the three-tier approach.

IV. Administrative, Data, and Enforcement Considerations

In any cost-benefit analysis relating to the three-tier system, one factor that must be considered is that such a system requires more complex regulations, a more extensive enforcement program and a more complicated data gathering and analysis effort than would be required for a system with a single ceiling.

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[6] DOE points out that even if the investment in No. 6 capability were justified at a later date due to increasing supply interruptions, there is a cost of installing the capacity earlier than necessary. DOE estimated that the annual penalty for installing residual oil burning capability earlier than it would otherwise be installed could range from $50-$72 million.

Under the Final Rule in this docket which implements the three-tier system, there is a certification procedure for determining the alternative fuel capability of incrementally priced industrial facilities. Certification must be made through the filing of an "alternative fuel capability affidavit" signed under oath and filed with the Commission if a facility is equipped to burn No. 5 or No. 6 oil and desires to be incrementally priced accordingly.

This in turn gives rise to an enforcement burden in that the Commission intends to audit a sample of certifications of alternative fuel capability to ensure compliance with the terms of its regulations and the NGPA.

Both the pressure on firms to file alternative fuel capability affidavits and the attendant administrative and enforcement burden would be relaxed for approximately 10 months under the exemption adopted herein. This will allow time for a further assessment of whether the benefits derived from a three-tier approach will, in the end analysis, be worth the administrative and other burdens involved.

As for data collection, the three-tier system poses a challenging assignment to DOE's Energy Information Agency (EIA). EIA has encountered some difficulties in carrying out its assignment to have in place three accurate price ceilings for each of a number of regions.

It is imperative that EIA have the first round of ceilings determined and published by December 20, 1979. Further, it is imperative that those established ceilings have an acceptably high degree of accuracy. Inaccuracy could engender load loss and a burdensome shifting of capital costs to residential and commercial customers. Moreover, the shifted load would place a demand on fuel oil markets this winter that could have undesirable consequences.

EIA's task would be greatly eased and the likelihood of statistically valid results greatly improved if, at the outset of the incremental pricing program, it were required to generate only one ceiling per region instead of the three that would be required under the three-tier approach. Abeyance of the first two tiers until November 1, 1980, would resolve any uncertainty about the ability of EIA to implement the ceiling system and assure that the ceiling system can be administered in an effective way.

V. Environmental Effects

The Environmental Protection Agency (EPA) strongly argued against the three-tier system and for a single No. 6 ceiling. It reasoned that a three-tier approach would cause industries to move from "non-attainment" areas where they are legally limited to using low sulfur No. 6 fuel oil to "attainment" areas where they would be permitted to use high sulfur No. 6 fuel oil.

The basic incentives for industry to relocate in attainment areas are the result of the 1977 Clean Air Act Amendments. The three-tier approach would only have an inconsequential impact in comparison. The Commission doubts any firms could decide to incur the capital cost associated with relocating just to get the benefit of being legally permitted to use fuel oil with a higher sulfur content and, thus, to get a lower gas price. The same benefit could obviously be gotten for a far lower price by installing emission control equipment.

EPA further argues that a three-tier rather than single-tier ceiling could reduce the incentive for industries to make the environmentally advantageous move from oil to gas. The Commission believes that the economic incentive to use gas would remain even with the three-tier system. However, the proposed period of exemption would provide an opportunity to evaluate further the environmental implications of the three-tier approach with the benefit of having the incremental pricing program actually in place.

VI. Conclusion

After evaluating the considerations discussed above, it is the Commission's conclusion that the public interest would be served by implementing the No. 6 high sulfur ceiling for all non-exempt natural gas consumers at this time and postponing implementation of the upper two ceilings until November 1, 1980.

This period of abeyance would permit all concerned to become familiar with the working of the incremental pricing program in practice as well as theory. The number and characteristics of the incrementally priced facilities will become clearer, and the price relationships among the various alternative fuels will be better understood. Thus, the ability to analyze and evaluate the amount of induced investment in No. 6 oil burning capability and its implications for the economic interests of the high priority gas consumers as well as consumers of fuel oil will be much improved by a period of upper tier abeyance. Additionally, implementation of an effective incremental pricing program would be eased if, during the first few months of the program, there were a single price ceiling rather than three ceilings.

Even beyond these public policy implications are broader energy policy implications in the choice between a single No. 6 ceiling and the three-tier system. These were articulated by the then Secretary of Energy, James R. Schlesinger, when DOE filed comments which were accompanied by a study in this proceeding. Secretary Schlesinger expressed the Department of Energy's view that it is in the national interest for natural gas to displace imported oil. Foreign oil is the marginal source of energy, and any fuel oil that is consumed instead of natural gas comes from the foreign barrel. Additionally, the Secretary observed that the nation's energy resources should be efficiently used. He noted that the total of the wellhead cost of natural gas plus variable delivery costs is currently below the cost of all alternate petroleum fuels on a national basis and is likely to remain so for some time. Thus, natural gas should be used to displace more costly petroleum. Based on these considerations, Secretary Schlesinger stated that the Department's preference would be to have the ceiling on incremental pricing set at the level of high sulfur No. 6 fuel oil.

Secretary Schlesinger went on to say, however, that, in the Department's view, if adoption of a uniform No. 6 ceiling decreased the surcharge absorption capability of incrementally priced facilities so must that, in at least some cases, the reduction from the No. 2 price level would offset the benefit to the high priority customer of avoiding load loss, then, under subsection 204(e) of the NGPA, the ceiling should not be reduced to a uniform No. 6 level.

The Commission agrees that the section 204 test is rather specific and it would not be appropriate for the Commission to base a decision on the several wider public policy concerns that are presented to it in this proceeding. Yet, the Commission believes that is must be cognizant of such concerns. Moreover, it is conscious that section 206 of the NGPA provides a mechanism for it to bring these public policy implications before the Congress. Hence, the Commission is promulgating this temporary exemption rule and transmitting it to Congress for review.

These regulations are prescribed as final regulations without further opportunity for comment because they rest upon the record already developed in this docket. In the Notice of Proposed Rulemaking in this docket, parties were invited to address not only the three-tier ceiling, but to address other approaches including, specifically, a one-tier ceiling established at the No. 6 level. Hearings were held in four cities across the nation, and over 50 written comments were received. To have further hearings at this time on the issue of whether there should be a three-tier or single-tier No. 6 ceiling until Novermber 1, 1980 would result in the replication of an already developed and ample record.

(The Natural Gas Policy Act of 1978, Pub. L. 95–621, 92 Stat. 3350, 15 U.S.C. 3301, *et seq.*)

In consideration of the foregoing, if neither House of Congress passes a

Resolution of Disapproval of the regulation transmitted to it in this order, Title 18 of the Code of Federal Regulations is amended in Part 282 to read as set forth below, effective December 1, 1979.

By the Commission.

Lois D. Cashell,
Acting Secretary.

[¶ 30,087]

44 F. R. 58667 (October 11, 1979)

18 CFR Part 290

[Docket No. RM79–6; Order No. 48]

Collection of Cost of Service Information Under Section 133 of the Public Utility Regulatory Policies Act of 1978

September 28, 1979.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final regulations.

SUMMARY: The Commission is amending certain portions of its final regulations governing the collection of cost of service information under section 133 of the Public Utility Regulatory Policies Act of 1978, including § 290.404—Customer groups to be reported and an additional § 290.603—Petitions for withdrawals of exemptions and extensions. Although only certain of the final rules are being amended, the rule is being published in its entirety for easy reference.

EFFECTIVE DATES: The amendments will be effective October 29, 1979. Petitions for rehearing on § 290.104 by October 29, 1979. Petitions for reconsideration of § 290.404 and § 290.603 by October 29, 1979.

ADDRESSES: Petitions should be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:
Gregory D. Martin, Office of Commissioner Matthew Holden, 825 North Capitol Street, NE., Room 9010, Washington, D.C. 20426, (202) 357–8383.
Jane Phillips, Office of the General Counsel, 825 North Capitol Street, NE., Room 8104–B, Washington, D.C. 20426, (202) 357–8033.
William Lindsay, Office of Electric Power Regulation, 825 North Capitol Street, NE., Room 5200, Washington, D.C. 20426, (202) 275–4777.

Introduction

On June 5, 1979, the Federal Energy Regulatory Commission (Commission) issued Part 290 as a final rule implementing section 133 of the Public Utilities Regulatory Policies Act of 1978 (PURPA) (44 FR 33847, June 13, 1979). Comments were invited on two sections of that rule, § 290.404(d) and § 290.404(f), to be received before July 15, 1979. Subsequently, the Commission issued a Notice of Opportunity to Petition for Reconsideration of certain sections of Part 290. It also advised that § 290.104 had been issued under the Federal Power Act (FPA), and that the FPA grants a right to Petition for Rehearing regarding that section.

The Commission has received over eighty filings on Part 290; five of these constituted petitions for rehearing on § 290.104. The filings represented approximately eighty parties, including almost seventy electric utilities, five State commissions, the National Association of Regulatory Utility Commissioners (NARUC), the Edison Electric Institute (EEI), the American Public Power Association (APPA), and the National Rural Electric Cooperative Association (NRECA). A list of those who submitted comments is included at the end of this preamble. Based on an analysis of the comments, the Commission has amended several sections of the final regulations effective October 23, 1979.

Summary and Analysis of Comments

Subparts A, B, and C

Three comments were received concerning the extension for small utilities in § 290.102(d). One comment[1] suggested that qualification for the extension should be based on the amount of total *firm* sales in order to exclude interruptible sales. The Commission based the extension provision in § 290.102(d) on the coverage qualification in section 102 of PURPA which is based on total sales. The Commission continues to believe that the extension provided in § 290.102(d) should parallel the coverage provision in the statute.

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[1] Bangor Hydro-Electric Co.

Another comment[9] indicated that the small utility extension is meaningless because small utilities will have to supply cost and load information before 1982 in order to implement section 112 of PURPA which requires that determinations on the Federal standards be made no later than two years after the date of PURPA enactment. The Commission disagrees with this comment. It is correct that consideration of the PURPA standards must *begin* no later than two years following PURPA enactment at which time filings by small utilities might not be available for use in those considerations. However, the State regulatory authorities and nonregulated utilities need not complete their evaluations until three years after PURPA enactment or, at the very latest, in the next rate case, at which time small utility filings will be available to aid in such considerations. Furthermore, section 112(a) permits any participant to request consideration of the Federal standards in any rate proceeding. Thus, evaluations made under section 112 of PURPA will be of an ongoing nature. In view of the importance of sparing the smaller utilities from unnecessary data-collection expense to the maximum extent practical, and in view of the fact that information on small utilities will be available for use in later rate proceedings in which the Federal standards are considered, we shall retain the extension provision. The additional time should permit small utilities to comply with the Part 290 requirements as economically as possible. In the interim, the data submitted by larger utilities may be helpful for evaluating small utilities' rate structures until direct data on small utilities are available.

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[9] NRECA.

A third comment [3] suggested that the Commission reduce rather than postpone the reporting requirements for small utilities because of the disproportionate costs to small utilities of doing load research and providing other information required under section 133. In recognition of these disproportionate costs, the Commission has already provided in § 290.403(d) that utilities having total retail sales of energy of less than one billion kilowatt-hours need collect sample metered data no more frequently than every five years. The Commission does not believe that additional relief is required or advisable.

For the reasons stated above, the extension for utilities with sales under one billion kilowatt-hours is being retained.

One comment [4] complained that the alternate reporting period provided for in § 290.103 was not available to nonregulated utilities because of the wording of that section. The Commission recognizes that such utilities frequently use a fiscal year for gathering information and has revised this section to provide an alternate reporting period for such utilities.

Nine comments were received concerning the filing date in § 290.103. Three comments [5] recommended that the date be changed from May 31 of the filing year to July 31 of that year; five comments [6] suggested that the date be changed to November 1 of the filing year. Several of the comments indicated that more time was required than the Commission had given in order to evaluate the data collected for the reporting year and that some of these data are not available until the middle of February. Several other utilities argued that, since the Form 1 report is due on March 31 of each year and the Form 12 report is due on April 30, additional time is needed under Part 290 to permit proper use of Form 1 and Form 12 information in the filings made under Part 290. The Commission recognizes the problems of analysis and reporting which are created by the May 31 filing date. On the other hand, the Commission believes that information gathered for purposes of section 133 should be as current as is reasonably possible. In light of these considerations, the Commission has revised the regulations to provide for a June 30 filing date.

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[3] UGI Corporation.

[4] APPA.

[5] Southern Company Services, Inc. on behalf of Alabama Power Co., Georgia Power Co., Gulf Power Co., and Mississippi Power Co. (Southern Company Services, Inc., *et al.*); North Carolina Utilities Commission; and Illinois Power Co.

[6] EEI; Carolina Power and Light Co., joint comments filed on behalf of Appalachian Power Co., Boston Edison Co., Commonwealth Edison Co., Consolidated Edison Co. of New York, Inc., Florida Power and Light Co., Indiana and Michigan Electric Co., Kentucky Power Co., Kingsport Power Co., Michigan Power Co., Ohio Power Co., Union Electric Co., and Wheeling Electric Co. (Appalachian Power Co., *et al.*); AEIC; and NRECA.

Five comments [7] criticized § 290.104 which prohibits including in wholesale rates any portion of the costs of complying with the regulations in Part 290. The comments argued that allocating administrative and general expenses incurred in complying with Part 290 between retail and wholesale would be difficult if not impossible, and that such a ratemaking provision is inappropriate in these regulations, has no foundation in PURPA and was not promulgated in conformance with notice and comment requirements. The comments also alleged error in the Commission's rationale that information collected under the rules involves only retail service and that the costs of collecting it should therefore be charged only to those customers.

The objections to the substance of this subpart are not persuasive. The Commission's role in the statutory scheme embodied in Title I of PURPA is, in effect, to function as a neutral stakeholder. The Commission is to specify information to be provided by covered electric utilities. However, the information will be used by State regulatory authorities, regulated and nonregulated utilities, and intervenors in considering rate design standards specified in Title I. Since this Commission does not have jurisdiction over retail rates, we cannot regard the cost of complying with section 133 as a cost incurred in the process of supplying services over which this Commission has jurisdiction. In addition, we note that many electric utilities covered by section 133 and the rest of Title I are the very wholesale customers to which the commenting investor-owned utilities would have us allocate some of the costs of complying the section 133. However, it is clear that allocating part of the cost of the wholesale supplier's cost of compliance to wholesale customers would be unfair because it would impose a double cost on such wholesale customers.

Nor does the Commission believe that § 290.104 was promulgated improperly. The section was promulgated under Part II of the FPA which authorizes the Commission to establish wholesale electric rates and is not prohibited under PURPA. Although § 290.104 was not included in the proposed regulations, the general issue of compliance costs was the primary focus of comments on the proposed rule. Because § 290.104 was promulgated as an outgrowth of those comments the Commission believes that it was promulgated in a procedurally proper manner. However, to remove any possible doubt that we have afforded full opportunity for comment on this section, we will entertain petitions for rehearing of this section of the final rule.

One comment [8] inquired whether the voltage levels mentioned in § 290.105(b) were provided as examples or whether collection of information for such voltage levels is mandatory. The Commission emphasizes that the levels were included in the rule by way of example and recognizes that reporting utilities may use different voltage levels based on the particulars of their individual systems.

Based on comments received from one utility, [9] the Commission has revised § 290.202(a) for purposes of clarity. The amendment makes clear that utilities are not required to report information separately for wholesale and retail customers.

One comment [10] objected to § 290.205, which requires the utility to design and report costing periods based on the accounting information supplied under Subpart B. The utility recommended that the section be eliminated because it alleged that the methodology for determining time-of-day rates based on accounting costs is imperfect. However, one of the purposes for data collection in section 133 is to facilitate the calculation of time-of-day rates based on accounting costs. Whether or not time-of-day rates can *correctly* be determined using accounting costs, a number of utilities do have time differentiated rates based on accounting costs. The Commission has more than once stated that it is not attempting to pass judgment on the merits of various rate setting methods, but is requiring instead that data be collected so that various methods can be tested. In order to facilitate such experimentation, the Commission is rejecting the comment and is retaining this portion of the regulation.

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[7] Appalachian Power Co., *et al.*, Southwestern Public Service Co., EEI, Houston Lighting and Power Co., and Pennsylvania Power and Light Co.

[8] Appalachian Power Co., *et al.*

[9] Public Service Co. of Colorado.

[10] Public Service Electric and Gas Co.

Six comments [11] objected to the requirement that marginal cost information, either raw or calculated, be provided. The Commission addressed the issues raised in these comments in pages 5 through 9 of the preamble to the final regulations issued June 5 and will continue to require the reporting of such information based on the discussion provided therein.

One comment [12] stated that the provision in § 290.303(a) requiring that the utility develop hourly marginal energy costs for a typical weekday, a typical weekend day and the system peak day for each month for a five-year period, while representing an easing in reporting requirements from the proposed rules, might "still require a very expensive computer program to produce the data." The comment urged the Commission to accept averaged marginal energy costs of on-peak and off-peak periods, rather than for every hour for such periods. The Commission believes that these hourly costs are an important element of the information needed to investigate whether a given choice of costing periods is reasonable and is retaining the requirement in its regulations.

Several comments were received on § 290.305, which requires information on distribution and customer costs. One comment [13] indicated that information on connection costs for the "average addition" within a major customer class is meaningless because the computation would produce data weighted by the particular mix of customers and voltage levels within the major customer class. A footnote has been added to § 290.305(a)(3) indicating that "average addition" does not require such a mathematical computation and that the utility will only be required to supply information on a "representative" customer addition. This comment also indicated that, while it did not agree with the minimum distribution system concept originally proposed and eliminated from the final rules, it felt that a zero intercept methodology should be required in reporting information on distribution and customer costs. The Commission eliminated the minimum distribution system concept from its final regulations because it did not wish to impose a single method on all reporting utilities at this time. For the same reason, the Commission declines to adopt the zero intercept methodology in its final rules.

In addition to the above changes, the Commission has made two editorial changes in Subpart C. Section § 290.305(a)(3) has been amended to indicate that nonrecurring labor costs should be included in each of the items required in § 290.305(a)(3)(i) through (iv) or in the separate item specified in § 290.305(a)(3)(v). One comment [14] observed that some of the titles and account numbers in § 290.306 are "obsolete." Our review indicates that the designation of some of the account numbers in the final rule is not in accord with the most recent version of the Uniform System of Accounts. The rule has been amended to correct the error.

Subpart D

Three comments [15] recommended that the Commission not require utilities to report pool and system load data for the same intervals of integration, as required in § 290.401(a). These comments indicated that such a requirement would produce less precise data in those circumstances where the pool reports on a 60-minute interval but the utility reports on a lesser interval. The Commission is in agreement with these comments and has revised its regulations to omit this requirement. However, we retain the requirement that system and class loads be reported using the same interval.

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[11] Alabama Power Co., Southwestern Public Service Co., Houston Lighting and Power Co., Hawaiian Electric Co., EEI, and UGI Corporation.

[12] Appalachian Power Co., *et al.*

[13] Public Service Electric and Gas Co.

[14] Hawaiian Electric Co.

[15] EEI, Appalachian Power Co., *et al.*, and Public Service Electric and Gas Co.

Two comments [16] suggested that the utility should be given the option under § 290.401(b) to report by jurisdiction or by the system as a whole. Section 290.401(b)(1) requires reporting by jurisdiction for certain load data unless the jurisdictions involved waive the requirement and permit system reporting. We believe this is a proper requirement and are retaining it in the regulations. Section 290.401(b)(2) requires reporting by the system as a whole for hourly load data unless one or more retail jurisdictions requests separate reporting. Section 290.401(b)(2) was included to minimize reporting burdens. However, if a utility prefers jurisdictional reporting of hourly load data, the regulations should permit it. Therefore, § 290.401(b)(2) has been revised to give the utility the option of reporting by jurisdiction if it chooses. The right of the jurisdictional authority to require such reporting is retained. A conforming amendment has also been made in § 290.403(a)(3). The Commission advises that the utility should feel free to submit the data required in this section if it so chooses even if it has elected under § 290.401(b)(2) to report by jurisdiction rather than the system as a whole. A third comment [17] suggested that the Commission establish a minimum number of customers or kilowatt-hours before jurisdictional reporting would be required. The Commission has redefined the customer groups for which load data will be required under Subpart D to include a reporting minimum.

One utility [18] objected to the requirement in § 290.402(a) that the system coincident peak be consistent with that reported in Form 1, apparently because it thought the peak loads reported in Form 1 excluded the loads of certain wholesale customers over a given size. Although Form 12 requires utilities to separate out such customer loads, page 431 of Form 1 requires reporting of the *total* system's coincident peak. Thus, no change in the regulations is necessary in this regard.

Several comments [19] addressed the requirement in §§ 290.402(c) and 290.402(e)(2) for reporting loads for the "winter peak." The comments questioned whether the term "winter" embodied a seasonal or a calendar year concept. Section 290.103(b) of the final regulations issued June 5 required that reporting be made on a calendar year basis. Thus, under the present rule, the winter season would be "split" in two by the new calendar year. Several utilities commenting on § 290.402(e)(2) stated that such a split could result in the reporting of two winter peaks for a single calendar year. In addition, the comments argued that many companies would conduct load research quite differently depending on whether the winter peak of the season occurred in December or in the immediately-following January or February. These comments explained that utilities may conduct their load research for other than a calendar year period, and may commence sample metering in either the Spring or the Fall. The Commission wishes to avoid the "split winter" reporting problem as well as the timing problem for the collection of sampled data. Because we had intended that information on the winter peak be provided on a seasonal rather than a calendar year basis, we are revising

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[16] Portland General Electric Co., and Philadelphia Electric Co.

[17] EEI.

[18] Public Service Co. of Colorado.

[19] Southern Company Services, Inc., *et al.*, Alabama Power Co., Consumers Power Co., Public Service Co. of Colorado, and AEIC.

§§ 290.103(b), 290.302(f), 290.402(c) and 290.402(e)(2) of the regulations to require that information be reported for the winter season immediately following the summer peak for which corresponding information is reported. In addition, the final regulations are being revised to allow sampling on other than a calendar year basis, commencing in either the Spring or the Fall.

Two comments [20] suggested that the requirement in § 290.402(e)(1) for reporting load duration curves be eliminated because such curves can be calculated based on other information required in § 290.402(e). They also argued that load duration curves are no longer used in constructing time-of-day rates. The Commission addressed this issue on pages 87 and 88 of the preamble to the final rules issued June 5 and is retaining this provision in its final rules for the reasons stated therein.

Two comments [21] were received concerning § 290.403(a)(4), which requires the utility to report hourly group loads for a *typical* weekday, *typical* weekend day, the group peak day, and the system peak day. The comments indicated that requiring hourly group loads for the *typical* weekday and weekend day would require a utility to collect hourly data for all days in order to average them to determine the "typical" period. Since the utilities will be collecting data for the reporting month by use of sample metering, the data necessary for averaging the hourly loads to determine the typical day loads will already be available. If sample metering is not undertaken under § 290.404, the regulations as revised and issued in this order require that these data be provided on a best estimate basis and that these data not be expected to constitute actual hourly averages. The regulations retain the requirements for typical day reporting. However, some clarifying amendments have been made to the terms used in this section.

One comment [22] suggested alternative wording for § 290.403(b) that would provide a utility with several options regarding load variables to be used in designing load research samples. We believe this comment is the result of a misinterpretation of the regulation as issued. The use of the phrase "group loads at the time of system and customer group peaks" in § 290.403(b) is intended to reduce the stringency of the accuracy requirement by making it applicable only to certain hours of the day rather than to the entire 24-hour period. This provision, a change from the rule as originally proposed, is discussed on pages 74 and 75 of the preamble to the final rule. As the comment points out, in the absence of load research data, the group loads at these times will not be known and therefore cannot be used in designing a specific sampling procedure. However, we believe that the time at which the system and group peaks occur can be estimated well enough to identify those time periods during the day for which the target accuracy is specifically sought. The Commission will not undertake to specify or limit the load-related variables that a utility may use in designing sampling procedures to achieve the stated accuracy target.

One comment [23] suggested that the utility be required to supply information in § 290.403(c) on the procedures which it used for extrapolating information from the sample. The Commission believes that this additional information is not essential to the load data reporting and declines to increase the reporting requirements further by changing the rules as suggested.

Several comments [24] suggested that the § 290.403(d) imposed unnecessary burdens by requiring large utilities to provide class load data for each reporting period based on actual measurements taken during that reporting period. One comment noted that the section provides relief for smaller utilities by requiring actual load measurement only once every five years, and suggested that a similar provision be provided for larger utilities. The comment argued that such a provision would permit continuous use of equipment and personnel between filing years without detriment to the quality of the resulting load data. According to the comment, the load characteristics of the mass of customers served under a given rate schedule or the end-use characteristics of a given electric device do not change significantly from one year to another. In its proposed rule, the Commission would have permitted a five-year period for load research activities for all utilities. Several comments objected to this provision on the grounds that the data would be too stale and that ongoing load research would be discouraged. After assessing both the comments on the proposed rule and the more recent comments, the Commission has concluded that the possible cost savings resulting from rotational metering outweigh the possible disadvantages of allowing it. The advisability of such a course is buttressed by amendments here made to § 290.404 which now requires sample metering of customers served under separate rate classes. Section 290.403(d) is being amended to permit a four-year period for actual measurement for utilities having annual retail sales greater than one billion kilowatt-hours. The five-year period applicable to smaller utilities is being retained.

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[20] Hawaiian Electric Co., and AEIC.

[21] Alabama Power Co., and Appalachian Power Co., *et al.*

[22] Hawaiian Electric Co.

[23] Detroit Edison Co.

[24] Southern Company Services, Inc. *et al.*, Alabama Power Co., and EEI.

The extensive comments on § 290.404 are summarized and discussed separately in the next section.

Section 290.405 of the final rule issued June 5 provided that a utility could use borrowed load data if granted an exemption under § 290.601 except that, for the November 1980 filing, it could use borrowed load data without obtaining such an exemption. A few comments [25] recommended that a utility be permitted to use borrowed load data without ever being required to apply for an exemption under Subpart F. We believe that the exemption process must continue to apply to sample metered load data for large rate classes defined in § 290.404(a) for the reasons discussed on pages 99 through 100 of the preamble to the June 5 final rules. However, for load data supplied on a best estimate basis for end-use classes and small rate classes, defined in § 290.404(b) and § 290.404(d), respectively, we believe it desirable for a utility to use load research borrowed from other utilities as a foundation for reporting on such end-use classes or small rate classes on a best-estimate basis, provided such data are adjusted properly for known differences relative to the original measurements. Section 290.405 has been revised to reflect this view.

One comment [26] was received on § 290.406(a) indicating that miscellaneous data required for specified customer groups would have to be estimated. These comments are correct regarding those end use customer groups specified in § 290.404(d) of the final rule issued June 5, and are also correct regarding those end use classes specified in § 290.404(b), as revised, to the extent that such classes are not served under separate rates. Accordingly, § 290.406(a) is being revised to require the reporting of actual data for customer classes for which there is a separate rate (including end-use classes) and estimated data for end-use classes for which there is not a separate rate.

One utility [27] suggested that a definition be added to § 290.406(a)(3) for the term "new customer." Section 290.401(e) defines "customers" as meters and makes this definition applicable to § 290.406. Therefore, we believe that no additional definition is required. By way of further explanation, we note that these "new customer" data are used to calculate certain unit costs which must be expected to be approximate. It is not essential that the count for new customers be precise.

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[25] See, *e.g.*, comments filed by UGI Corporation.

[26] Portland General Electric Co.

[27] Public Service Co. of Colorado.

Summary of Comments § 290.404

The majority of comments received on Part 290 concerned § 290.404 of Subpart D, defining the classes for which load and cost data are to be separately reported. Almost all of the parties discussed § 290.404(d) (end use classes); about one-third discussed § 290.404(f) (exemption for time of day customer groups). In connection with comments on § 290.404(d), many of the comments also discussed § 290.404(b), which required reporting of load data by major customer classes, and § 290.404(c), which specified the timing requirement for reporting by end use. Several parties commented on § 290.404(e), the extension provision for all other rate schedules and consumption patterns.

The most pervasive comment on both the end use classes specified in § 290.404(d), and the major customer classes, specified in § 290.404(b), recommended that the Commission use a definition of customer class based, as in the proposed rule, on whether the customer class is served under a separate, identifiable rate schedule. The major criticism of major customer class, reporting was that the designated major customer classes, represented revenue classifications and did not comport with the way utilities actually serve customers under rate schedules.[28] Four comments [29] pointed out that customers are classified for rate purposes on the basis of type and size of load and load patterns rather than on business characteristics. Those commenting on the major customer classes focused particularly on the categories "commercial use (office buildings, stores, shopping centers, etc.)" and "industrial use (factories, etc.)," and argued that many utilities use general service rate schedules under which factories as well as office buildings are served. Thirteen of the comments [30] specifically urged the Commission to use *rate* classes, not *revenue* classes, for reporting principal customer classes, because section 133 of PURPA requires collection of data for purposes of determining the costs of providing electric service by class of customer, if such classes are served under separate rate schedules. Another comment [31] questioned whether data should be reported for very broad classifications if these data are to be used to analyze rate structures under Title I of PURPA. Yet another comment [32] argued that section 133 should be implemented so as to produce data applicable to cost allocation rather than aggregate statistical reporting, and that the broad major customer classes specified in §290.404(b) were insufficient in this regard. Several other parties [33] urged that the major customer class definition track Form 1 reporting, so that utilities could classify customers, as between small and large commercial and industrial loads, as they normally report them on Form 1, rather than having to separate the load by type of business activity. Form 1 allows the utility to categorize "small" versus "large" commercial and industrial sales as they regularly would classify those sales so long as the customer demands for the smaller category are not greater than 1,000 kilowatts.

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[28] *See, e.g.,* comments filed by Detroit Edison Co., Dallas Power and Light Co., Southern Company Services, Inc., *et al.,* Hawaiian Electric Co., and Appalachian Power Co., *et al.*

[29] Hawaiian Electric Co., Commonwealth Edison Co., Appalachian Power Co., *et al.* and the New York Public Service Commission.

[30] Dallas Power and Light Co., Texas Electric Service Co., Public Service Electric and Gas Co., Pennsylvania Power and Light Co., Philadelphia Electric Co., Consumers Power Co., Tampa Electric Co., EEI, Montana Power Co., Illinois Power Co., Appalachian Power Co., *et al.,* Alabama Power Co., and Texas Power and Light Co.

[31] Southern Company Services, Inc., *et al.*

[32] EEI.

[33] Baltimore Gas and Electric Co., and joint comments filed by Portland General Electric Co. Pacific Gas and Electric Co., and Puget Sound Power and Light Co. (Portland General Electric Co., *et al.*).

Several respondents[34] criticized the requirement in §290.404(c)(2) that load data be reported for the specified end use classes starting in 1984 even if the utility has no separate rate schedule serving that end use. The comments argued that, since the categories do not generally correspond to rate schedules, customers having the specified end uses would be difficult, if not impossible, to identify. The comments argued that the regulations as promulgated would require complete surveys of all retail customers to determine which had the specified end uses; that customers responses to those surveys could not be relied upon; and that the surveys would have to be conducted continually in order to maintain current information on appliance ownership. Several of the comments[35] recommended that reporting of end-use load characteristics be limited to those loads that are served on separate rates or riders, or that are otherwise identifiable as significant components of the total sales or demands of the utility.

Only one comment[36] supported §290.404(d) as issued for comment. All other comments were adverse, either with respect to the specific list of end uses or with respect to the inclusion of such a list in the regulations. Comments on the specific list of end use categories included suggestions that residential space cooling be included[37] that basic residential use and low-income residential use be included,[38] that public education or schools be reported[39] and that wholesale for resale service be reported as a separate class.[40] One comment[41] urged the Commission to limit the metering requirement to customers falling into one or more of the following categories:

Residential space heating
Residential space cooling
Non-residential space heating
Non-residential space cooling

A number of utilities[42] stated that they had so few customers in the designated categories of master-metered multiple dwellings, electric heat, large electric drive motors, or irrigation, that separate load data on these categories would not be useful. Many parties opposed the inclusion of any end use list in the regulation. They articulated the following principal arguments:

1. No single list is applicable to all utilities in terms of the criteria stated by the Commission.[43]
2. The categories are not mutually exclusive.
3. There is no indication that the end uses in such a list would be cost-distinctive.
4. Numbers of customers in some end-use categories will be so small that statistical sampling would not meet the accuracy requirement.
5. Requirements based on a list of end uses would eliminate the usefulness of current load research results.
6. Collection of load data by end use will not implement the purposes of Title I of PURPA.

The comments included the following principal recommendations:

1. End uses should be specified by the State regulatory authorities.[44]

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[34] Massachusetts Electric Co. and Narragansett Electric Co. (Massachusetts Electric Co., *et al.*).

[35] *See, e.g.*, comments filed by Detroit Edison Co., and Central Maine Power Co.

[36] National Retail Merchants Association (NRMA).

[37] Detroit Edison Co., Georgia Power Co., Florida Public Service Commission, Salt River Project, and Appalachian Power Co., *et al.*

[38] National Consumer Law Center.

[39] Clark County School District.

[40] EEI.

[41] Appalachian Power Co., *et al.*

[42] See, *e.g.*, comments filed by Detroit Edison Co., Southern Company Services, Inc., *et al.*, Tampa Electric Co., Puget Sound Power and Light Co., and Georgia Power Co.

[43] Citing the preamble to the final regulations at page 70.

[44] Portland General Electric Co., Georgia Power Co., Tacoma Dept. of Public Utilities, Arizona Public Service Co., Montana Power Co., New York State Electric and Gas Corporation, and joint comments filed by Central Power and Light Co., Public Service Co. of Oklahoma, Southwestern Electric Power Co., and West Texas Utilities Co. (Central Power and Light Co., *et al.*).

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2. The regulations should specify the criteria for end-use selection, not the specific end-uses themselves.[45]

3. Each utility should specify the end use categories that have a significant system impact.[46]

4. To be a category for required reporting, an end use should account for at least five percent or ten percent of the system's kilowatt-hours.[47]

5. The end use requirement should be completely eliminated, since it would not improve costing and rate design for class rates, which are based on total usage, not end uses.[48]

Several comments [49] suggested alternative ways to impose separate load data reporting by customer class. One comment [50] suggested that the Commission require the load data, as well as the other data on number of customers and kilowatt-hour sales, for any retail rate schedule representing more than three percent of the energy supplied at retail. The comment suggested that the utility be required to include in its sampling plan data on such items as a customer's income level, usage of electrical appliances or devices, and kilowatt-hour usage in order to facilitate development of data on different consumption patterns within such rate schedules. It was further suggested that load data for customers served under rate schedules representing less than three percent of retail sales and data on the major customer classes specified in § 290.404(b) be reported on a best estimate basis unless a State regulatory authority required sample metering for these categories.

One comment [51] proposed that utilities be required to provide best estimates (not sample metered data) for major end uses and sample metered data (not best estimates) for major customer classes and rate classes. The comment suggested that the State regulatory authority use criteria established by the Commission to evaluate major end use classes proposed by the individual utilities, in order to account for regional and local differences in utilities' loads.

One comment [52] asserted that because inclusion of the end use sample metering requirement in the June 5 final regulations provided only limited opportunity for comment, inclusion of that section violated basic procedural requirements applicable to rulemakings. The comment also alleged that the record in this proceeding did not justify requiring sample metering for end-use groups and that the Commission had not adequately supported its decision to include this provision in the final rule. Two comments [53] asserted that the Commission lacked any authority in any circumstance to require reporting by end use.

A large proportion of comments suggested that § 290.404(d) could be interpreted to require metering of individual end use loads inside a customer's premises: *i.e.*, appliances. Many of these comments contained extensive arguments against such submetering; others requested that the point be clarified.

Seven parties [54] criticized the provision in § 290.404(e) extending until 1985 the requirement to report load data for rate classes or different consumption patterns not otherwise covered in § 290.404 (b) and (d). Most of these respondents believed the extension should be changed to an exemption because collection of load data on each and every rate class, including small classes, would be expensive and would not be cost effective. Two utilities [55] requested that the Commission redefine the customer classes to which the extension would apply by redefining "different consumption patterns" within a class. The comments agreed that otherwise utilities might eventually be required to meter each customer served since each customer would have a different consumption pattern. One of the comments suggested changing the words "a separate rate" to "a separate rate schedule" in order to make the extension more precise.

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[45] Pacific Power and Light Co., Hawaiian Electric Co., and Carolina Power and Light Co.

[46] Southwestern Public Service Co., Public Service Co. of Indiana, and North Carolina Utility Commission.

[47] Iowa-Illinois Gas and Electric Co., Northeast Utilities Service Co., and Central Power and Light Co., *et al.*

[48] Joint comments filed on behalf of Arkansas Power and Light Co., Arkansas-Missouri Power Co., Louisiana Power and Light Co., Mississippi Power and Light Co., and New Orleans Public Service, Inc. (Arkansas Power and Light Co., *et al.*).

[49] *See, e.g.*, comments filed by Southern Company Services, Inc., *et al.* and Portland General Electric Co., *et al.*

[50] Southern Company Services, Inc., *et al.*

[51] Portland General Electric Co., *et al.*

[52] Appalachian Power Co., *et al.*

[53] Georgia Power Co. and Gulf States Utilities.

[54] Dallas Power and Light Co., Tampa Electric Co., Georgia Power Co., Hawaiian Electric Co., Public Service Co. of Colorado, Public Service Electric and Gas Co., and National Consumer Law Center.

Another party [56] opposed the extension in § 290.404(c) on different grounds. It argued that the data collected under Part 290 would be of "minimal value" if an extension were granted to 1985 because the State regulatory authorities will have completed their review of utility rates under other sections of Title I of PURPA within two or three years of enactment; *i.e.*, well before these data would be available. It suggested that, at the very least, best estimates be reported by 1980 and sample metered data by 1982 so that some use could be made of these data during rate structure evaluations by State regulatory authorities. It also questioned the Commission's authority to grant the extension in § 290.404(e) as well as the small utility extension in § 290.103(d) for utilities with less than 1 billion annual kWh sales, arguing that extensions can be granted only on an individual, case-by-case basis rather than on a blanket basis.

More than half [57] of the twenty or so comments addressing the exemption in § 290.404(f) from reporting load data for customers served under time of day (TOD) rates, supported the exemption without elaboration. One utility [58] favored the exemption but indicated that some voluntary submissions of load data on TOD customers would be useful. Another utility [59] suggested that the exemption be broadened to include any utility "whose long-run marginal costs are less than the long-run average costs." Yet another utility [60] suggested that the exemption be broadened to include all customer groups for which it can be shown that TOD rates are not cost-beneficial. Another utility [61] proposed that any customer using load management techniques, either self-imposed or imposed by the utility, should also be exempted. A State regulatory authority [62] recommended that the exemption be expanded to include customers served under interruptible or controlled service rates. Another utility [63] recommended that the exemption be expanded to include certain information not unique to TOD customers or information that is available on customer groups for which sample metering is required. Similarly, another party [64] felt that requiring in § 290.406(a) that the utility report kilowatt-hour sales and number of customers for TOD customers was burdensome and inconsistent with the exemption from collection of load data for such customers. All the comments opposing the exemption in § 290.404(f) [65] observed that a useful source of information would be lost if load data were not obtained on TOD customer groups.

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[55] Hawaiian Electric Co. and Public Service Co. of Colorado.

[56] National Consumer Law Center.

[57] Iowa Southern Utilities Co., City Public Service Board of San Antonio, Public Service Commission of Wisconsin, Central Power and Light Co., *et al.*, Florida Power and Light Co., Texas Electric Service Co., AEIC, Consumer's Power Co., Arizona Public Service Co., Carolina Power and Light Co., and Texas Power and Light Co.

[58] Detroit Edison Co.

[59] Southwestern Public Service Co.

[60] Houston Lighting and Power Co.

[61] Missouri Power and Light Co.

[62] Michigan Public Service Commission.

[63] Central Maine Power Co.

[64] EEI.

[65] NRMA, Florida Public Service Commission, National Consumer Law Center, Northeast Utilities, and Public Service Co. of Colorado.

Analysis of Comments and Revisions to § 290.404

The Commission is revising § 290.404 in its entirety based on the extensive comments received on the requirement in § 290.404(d) to report sample metered load data by end use; based on the numerous comments received on the best estimate reporting requirement in § 290.404(b) for major customer classes; and based on the interrelationship between these two sections.

Section 290.404, as revised, adopts the suggestion contained in the majority of the comments, that load data be reported for customers served under separate rate schedules.[66] The Commission believes that reversion to data collection based on rate classes is the preferable course because the data collected under section 133 will aid in evaluating rate structures and will provide cost allocation information necessary for formulating alternative rate designs. As revised, this provision tracks more closely the statutory language of section 133(a)(2) which requires reporting of representative load data for "each customer class for which there is a separate rate."

When the Commission proposed in its Notice of Proposed Rulemaking that separate load data be collected for each customer class for which there is a separate rate, several utilities complained that they would be required to collect load data for too many rate classes.[67] Based on these comments and on suggestions received during the most recent comment period that the Commission limit the number of rate classes for which reporting would be required, the Commission has established a percentage size limit to determine for which rate classes sample metered load data will be required. This size limit is to be applied to those rate classes existing at the end of the year preceding the reporting year. Sample metered load data will be required for customers served under separate rate schedules only if those groups have kilowatt demands of ten percent or more of any of the utility's monthly peaks or constitute ten percent or more of the utility's retail sales in any month during the reporting period. For purposes of establishing which rate classes meet the size limit, the regulations require that the utility aggregate all classes served under rate schedules which are identical except for the differences in the customer charge or the initial block intended to reflect differing transmission or distribution costs associated with the particular location of the community served. All other rate classes must be reported on a best estimate basis only.

Some comments objected to reporting load data separately for rate schedules identical except for a varying customer charge or a varying initial block. Under § 290.404(c), the utility will be required or permitted to report such rate classes as a combined class depending on whether they constitute a large or a small rate class in the aggregate. However, such combined reporting is subject to the jurisdictional reporting requirements of § 290.401(b). This provision for combined reporting, in conjunction with the ten percent size limit on rate classes to be reported on a sample metered basis, should reduce the groups for which most utilities must sample meter to a manageable number.

Nearly all of the comments opposed the requirement that load data be collected and reported by end use. Perhaps the strongest objection reflected an understandable confusion about whether the rules required submetering of customers' premises to determine the particular appliance load or whether the requirement pertained to customers' total loads, including the specified end use. The second major objection was that the end use categories were not mutually exclusive. Yet a third principal objection was made that the list of end uses was inapplicable to specific utilities' loads either because the extremely limited number of customers in the end use category required sample metering of almost every customer within the group or because major loads of the utility, like cooling, were not included in the list. Although the requirement for reporting by end use classes has been retained in the final rule, substantial changes have been made in the rule in order to clarify its coverage and to eliminate the sample metering requirement for end use classes.

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[66] See, *e.g.*, comments of EEI, and Southern Company Services, Inc., *et al.*

[67] See preamble to the final regulations at page 67.

The Commission has decided to retain the reporting requirement for the end use groups for several reasons. The statutory language of section 133(a)(1) of PURPA suggests that one of the purposes for data collection under this section of Title I is to facilitate costing for subclasses displaying distinctive consumption patterns within a rate class. If a utility serves large numbers of customers with many different load shapes under a single rate, load data reported for the rate class as a whole would not provide sufficient information to determine the costs of serving different consumption patterns within the rate class and to analyze the extent to which more than one rate for the class would more closely reflect the costs of serving customer groups within the rate class which have uniquely different load shapes. Cross-subsidies within rate classes could not be detected. One way to remedy such a deficiency and identify groups with different consumption patterns is to group customers by their end uses and to require separate reporting for those end use groups.

The second and even more compelling reason for retaining load data reporting for end use groups is to provide information useful for testing the cost justification for rate blocks within a rate schedule. Such an exercise is important both for determining the reasonableness of current blocking and for designing rates that may be used in lieu of time-of-day rates which may not be cost effective for some customer groups because of high metering costs. Blocked rates could be designed to reflect the costs imposed by the daily load pattern for certain end uses. For example, if residential space heating were on the system's daily peak during the winter, the data could be used as the basis for arguing for a seasonal rate for residential customers with an inverted tail block for the winter season. We recognize that load information for the different consumption patterns within a class of customers served on time-of-day rates is not necessary for time-of-day rate *design*. However, such data may facilitate the transition to time-of-day rates by helping to predict the level or revenues to be expected under time-of-day rates and the expected changes in overall class load shapes that may result from instituting time-of-day rates.

The end use classes in the final rule have been clarified to refer to the total loads of customers with the particular end use; restructured to be mutually exclusive; and limited to certain end uses within the residential and commercial categories. Rather than retain the full list of end uses proposed in the final regulations issued June 5, we have limited the categories to those representing a large portion of the residential and commercial loads and those representing identifiable and homogeneous load shapes within rate classes. A size floor has been placed on the end use classes to avoid reporting load data for small end use classes. The end use class need not be separately reported if it represents less than five percent of the utility's retail energy sales in every month of the reporting period.

The first end use class contains "residential customers not using electricity for either water heating or whole-residence space heating." This group is intended to capture, among other things, basic use by residential customers. By comparing the daily load shapes of this customer group for the various seasons of the year, the pattern of air conditioning use may be distinguished from basic use. This category was included both to satisfy the comments that data on basic residential use characteristics were necessary to test the cost-effectiveness of lifeline rates [88] and to respond to many of the southern utilities' comments that we had excluded residential air conditioning, which is a major portion of their loads, from the specified end use classifications.

We have declined to provide more explicitly for separate collection of load data on air conditioning for several reasons. The major one is the difficulty in categorizing customers with air conditioners. Unlike space heating, there are wide variations in the number and types of air conditioners, ranging from single room window units to central air conditioners. Also, unlike space heating, there is seldom a separate rate for air conditioning. Such a rate would constitute; in most cases, a surcharge rather than a discount such as might be established by a summer peaking utility for a winter space heating load. Customers could not be expected to identify themselves by applying for such a rate. A utility would have great difficulty keeping track of air conditioning customers it had identified especially because room air conditioners can be installed and removed with relative ease. However, these regulations do not bar southern utilities from conducting load studies on their own initiative in order to determine air conditioning loads for their own systems.

The second category of end-use customers is "residential customers using electricity for water heating but not for whole-residence space heating." This category contains customers with basic residential use plus electric water heating. The third category is "residential customers using electricity for whole-residence space heating and other uses (includes but is not limited to all-electric homes.)" This category contains customers with basic residential use plus electric water heating and space heating. All-electric homes would be included in this third category along with homes with gas appliances (other than for water or space heating) for cooking and/or clothes drying. We understand from the comments that most customers with electric space heating also have electric water heating; thus, in order to avoid appliance metering, we have combined these two end uses in the third category. General load shapes for water heating can be obtained by comparing category one to category two, and general load shapes for space heating can be obtained by comparing categories two and three.

The fourth category is "customers operating mastermetered multiple dwellings." To the extent there remain any master metered multiple dwellings on a utility's system, it is important to identify the load shapes for this group separately. Electricity consumption by customers in this category is likely to be less responsive to price changes than consumption by most other customers served with master metered multiple dwellings under a general service rate schedule because the utility's actual customer cannot control occupants' consumption and the final user generally pays for electricity only indirectly as a portion of the rent. Separate identification of the load characteristics of mastermetered multiple dwellings will aid in determining under section 115(d) of Title I of PURPA whether this form of billing should be continued or instituted.

The fifth and sixth end use categories are, respectively, "customers operating commercial office buildings not using electricity for primary space heating;" and "customers operating commercial office buildings using electricity for primary space heating (includes but is not limited to all electric buildings)." These are the only categories for nonresidential end uses retained in the final regulation. The difficulties with identifying the residential air conditioning load as a separate load apply equally to commercial office buildings. In addition, the air conditioning load is not separately identified as a commercial end use class because in many areas of the country, this air conditioning has virtually complete saturation. We believe that these last two categories are the most easily identifiable of the nonresidential loads and represent categories for which separate rates have already been established by many utilities.

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[88] Comments of National Consumer Law Center. However, its request for load data on daily use patterns separating out low-income residential customers will not be adopted. Such reporting is not required under section 133, and the Commission declines to impose such an additional burden on the utility at this time.

The Commission recognizes the need to proceed cautiously in requiring separate reporting of load data in view of the costs imposed by such reporting requirements. We recognize that there are other categories within rate classes than those listed in § 290.404(d), *e.g.*, public schools.[69] The end use classes identified in these final regulations represent a first step in carrying out the statutory requirements of section 133. The Commission envisions that these rules will evolve as more is learned about rate structures through evaluations made at the State level.

The final regulations require sample metering only for large rate classes. Best estimate reporting rather than sample metering is required for small rate classes and for customers with the specified end uses. Our decision regarding end use metering is based on many comments regarding the problems inherent in identifying customers with the specified end uses. However, if an end use is served under a distinct rate schedule and it qualifies as a large rate class, sample metering will be required. We recognize that the requirement to meter only large rate classes may create an incentive for utilities that have several, separate, large rate classes for end uses (including but not limited to those specified in § 290.404(d)) to collapse those classes into a single, broad rate class so as to avoid having to meter such end uses separately. If it appears that such rate revision is being undertaken solely as a result of the regulations on sample metering, a revision to Part 290 will be in order or extensions granted to the utility for reporting end uses may be withdrawn.

The schedule for reporting best estimates and sample metered data is similar to that established in the June 5 final regulations. In 1980, load data for large rate classes are to be submitted on a best estimate basis; in 1982 and subsequent filing years, they are to be submitted on a sample metered basis. For small rate classes, best estimates are required beginning in 1982. For end use classes, best estimates are required beginning in 1980. The Commission wishes to avoid any duplication of reporting for rate classes and end use classes. Therefore, § 290.404(c) provides that, if an end use class corresponds to a rate class and qualifies under the 10 percent size limit, it should be treated as a rate class, not as an end use class, for purposes of complying with Part 290.

A new paragraph has been added to § 290.404 to define more clearly what is meant by "best estimate" reporting and to differentiate between the expected quality of the data for large rate classes, small rate classes and end use classes. All best estimate load data are to reflect the utilities' best judgment. The Commission expects that the quality of best estimates will improve over time and that utilities will attempt to stratify their rate classes so that the sample selection may include some consideration of end use loads covered by the end use classes.

As we indicated in the preamble to the final rules, we recognize that borrowing load data from other utilities in order to estimate loads for large rate classes may produce unacceptable estimates. For estimating load patterns for the end use classes, however, we would expect that borrowed data on specific appliance loads, obtained from either industry-wide or regional load research, could be used as a basis for the estimates when combined with information about appliance saturation on the reporting utility's own system.

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[69] Clark County School District.

Similarly, borrowed data for the small rate classes could provide good and improving estimates of load shapes for these classes.

In order to ensure that best efforts are made to estimate load data where sample metering is not required, the final regulations estop a utility beginning in 1982 (for end use classes) from challenging its best estimate as insufficiently reliable for use in evaluating and determining rates under title I of PURPA.

We believe, as a legal matter, that sections 133(a)(1) and 133(a)(2) of PURPA require that cost, hence load, data be reported for "*each* electric consumer class" served under a separate rate including "different consumption patterns" within such class. We realize, on the basis of information presented to us in this proceeding, that severe, practical difficulties exist in meeting this requirement in the time period allowed for first reporting. The extension mechanism provides a device for harmonizing the statutory directive with these practical considerations. Since we believe that Congress desired that a reasonable reporting program be instituted, we have used our extension authority to try to reduce the difficulties of adhering to all of the reporting requirements in the statute by the first filing. Thus § 290.404(e) of the final regulations issued June 5 contained an extension to 1985 for reporting load data for rate classes and for different consumption patterns not specified in § 290.404 (b) and (d) of that rule.

We have now determined to shorten this extension in the case of small rate classes. Beginning in 1982 the utility will be required to report load data for small rate classes. This new reporting requirement will enable all users of the data to aggregate the class data to system-wide data so that review for consistency is facilitated. Additionally, rate classes that fall into this category, although "small" when viewed individually, may constitute a substantial portion of the total load. We do not believe that the costs of sample metering each of the small rate classes are warranted since, as many utilities have indicated, many of these loads are predictable and can be estimated fairly well using means other than sample metering. The reporting is thus required only on a best-estimate basis. The Commission has provided procedures in § 290.603 whereby a party may make a showing under § 290.603(a)(3)(i) that such good cause no longer exists in regard to a particular utility.

The Commission is also granting a reporting extension in § 290.404(f) to January 1, 1988, for all different consumption patterns wholly contained within a rate class and not specified in § 290.404(d). Because the costs of sample metering for large rate classes and providing estimates for small rate classes and those end uses specified in § 290.404(d) are expected to be extensive, we do not believe that requiring utilities to incur additional costs for estimating loads for additional end uses is warranted at this time. As we have stated on several occasions, we intend to re-evaluate the extension for reporting additional end use classes provided in paragraph (f) of revised § 290.404 in order to determine whether good cause continues to exist for granting it. The Commission will undertake such a re-evaluation after reviewing the 1980 filings made under this part.

We disagree that an extension or exemption can be granted only on a case-by-case basis. The Commission believes that granting blanket extensions and exemptions is an appropriate procedure for determining the schedule of compliance with section 133. Although good cause must exist with regard to each utility before an extension may be granted, the statute does not require that each and every utility demonstrate such good cause. For the reasons discussed on pages 71 through 73 of the preamble to the June 5 regulations, the Commission believes that good cause exists to grant an extension to 1988 on an industry-wide basis for reporting end use classes not specified in § 290.404(d) which account for less than five percent of the utility's retail electric sales for every month of the reporting period and which constitute different consumption patterns within the rate class. The eight-year extension will provide the Commission ample time to determine the benefits to be gained from requiring separate reporting for these end use classes.

The Commission also believes that good cause exists to grant such an industry-wide extension for such end use classes if they account for more than five percent of its retail sales in any such month and are not required to be reported in § 290.404(d). This conclusion is based on the showings by several utilities that reporting for additional end uses is a difficult and costly process. Neither sound administrative principles nor the words of the statute require us to compel every utility to come in and certify that the general grounds for this extension for large, unspecified end use classes (over five percent, not specified in § 290.404(d)) apply to it. Nor would it be feasible, in the time available, for the Commission to review and compare existing rate schedules and large, unspecified end use classes for all utilities in order to satisfy itself completely that the generally-applicable good cause exists regarding each and every utility, and that the extension will have precisely the same effect in every instance. However, the rationale for the extension gives every reason to assume that the good cause for the extension shown by several utilities is valid industry-wide; no comment has identified a particular large, unspecified end use class to which the rationale does not apply.

An additional reason for granting the extension regarding additional end uses which cause different consumption patterns within a rate class and which exceed the five percent size limit is the Commission's inability to devise a satisfactory, generally-applicable quantitative test by which such end uses can be identified as important to the load profile of each particular utility. Nor has any comment suggested such a test. (Indeed, such a general test would have to be cast in terms of deviations from a class norm, information which will not be known for most utilities until the 1980 or 1982 filings are made under this regulation.) To some extent the extension for end uses, as it applies to large, unspecified end use classes, is being granted to defer action until a day when the Commission is better able to give concrete definition to the statutory language concerning "different consumption patterns within a class." We observe that the only other proposed solutions to this definitional problem suggested delegating this responsibility to the electric utilities themselves or to the State regulatory authorities and non-regulated utilities.

We note, however, that the utilities have now and will continue to have the authority to conduct such additional load research, surveys, and cost studies as they deem necessary to determine the costs of serving distinct subclasses; to our knowledge all the State regulatory authorities have the authority to compel such studies by the utilities within their jurisdiction. Nothing in section 133 or these regulations changes this situation. Furthermore, we note that the procedures provided in § 290.603 permit affected customers or the Secretary of Energy to seek withdrawal of an extension in the case of a particular utility if they believe that an extension for a particular utility is not warranted. By granting extensions and providing this petition procedure, we have reserved to the Commission the authority Congress placed with us to interpret and apply this and the other provisions in section 133. The Commission emphasizes that good cause regarding large, unspecified end use classes is based primarily on administrative considerations and that it has not prejudged the extension's applicability, on grounds relative to particular utilities, for purposes of acting on applications for withdrawals submitted under § 290.603.

Section 290.404(h) contains an exemption for customer classes served under time-of-day rates. The exemption appeared as § 290.404(f) in the June 5 final rule and is being retained for the reasons articulated on page 73 of the preamble to that rule. The Commission notes that, even though some valuable data may be lost due to the extension, utilities are not barred from collecting these data on their own initiative or upon order of the State regulatory authority. For the reasons articulated concerning blanket extensions, we do not believe that granting such a blanket exemption is procedurally incorrect. However, we have provided procedures in § 290.603 whereby a party can seek to have the exemption withdrawn for a particular utility if the party believes it is no longer valid for that utility.

Subpart E

One comment [70] recommended that § 290.502 be modified so that a utility need not report calculated marginal costs unless specifically required to do so by its State regulatory authority. The Commission addressed the issue of calculated vs. raw data reporting beginning on page 9 of the preamble to the final regulations issued June 5. For the reasons stated therein, the Commission will continue to require that marginal costs be calculated.

Another comment [71] contended that Table 2 ignores certain important distinctions needed for the calculation of marginal costs. For example, the comment contended that the table is deficient because it makes no provision for the "location of facilities relative to the customer" in presenting marginal cost information. It is our understanding that the comment suggested a refinement rather than an amendment of error in the reporting requirements for marginal cost calculations. There is no bar to a utility's including such a refinement in its calculations. However, the Commission declines to impose such a requirement on all filing companies. This comment also suggested that Table 2 show only one customer class since the marginal dollar per kilowatt will be identical for all classes for generation and transmission data. The Commission has issued both Table 1 and Table 2 in a format that will accommodate various methods of costing undertaken by parties complying with these regulations. In doing so it has imposed no requirement that the generation and transmission costs per kilowatt differ among customer groups if the submitting utility believes such costs to be identical.

Another comment [72] urged the Commission to limit marginal cost calculations to those customer classes for which sample metering is required. The Commission believes that the metering requirement will impose a heavy burden on many utilities and is thus limiting the classes for which sample metering is required. Nevertheless, costing data, albeit on a best-estimate basis, will be retained for other customer classes so that complete rate evaluations can be carried out under Title I of PURPA.

Subpart F

One party [73] argued that the eighteen-month requirement in § 290.601 for submitting an exemption request to the Commission would prohibit use of the compliance plan approach advocated in its comments on the proposed rule. The comment argued that, under § 290.601, a State regulatory authority would be required to receive the exemption request two years prior to the time the filing is required under § 290.102 in order to review the request prior to the Commission's acting upon it. The Commission deems the eighteen-month period necessary for allowing time for notice and comment and Commission analysis and action on exemption requests by utilities. Imposition of a shorter time period would not provide a utility denied an exemption adequate time to supply the necessary information. The Commission believes that concurrent review by the Commission and the State regulatory authority is sufficient to implement the reporting requirements in Part 290 and declines to amend the regulations as requested.

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[70] Hawaiian Electric Co.

[71] Southwestern Public Service Co.

[72] Central Maine Power Co.

[73] NARUC.

Two comments [74] suggested that § 290.601(d) require that a summary of the exemption application rather than the entire application be published in newspapers of general circulation. The Commission accepts this suggestion and is modifying the regulations accordingly. The Commission advises, however, that a utility which fails to provide an adequate summary of its exemption application will be deemed to have violated the notice provisions of this section and will be unable to avail itself of any exemption granted by the Commission in response to that application.

Additional Petition Procedures

Although this order amends only portions of Part 290, it is being published in its entirety, inclusive of the amendments discussed in this preamble, for easy reference. Parties are informed that under PURPA they have the right to Petition for Reconsideration on § 290.404 of Subpart D and on § 290.603 of Subpart F. Their right to further reconsideration of other sections of Part 290 has been exhausted. Petitions for Reconsideration of § 290.404 and § 290.603 will be considered if filed by October 29, 1979. In addition, parties are informed that the Commission is affording a right to rehearing on § 290.104 and that petitions must be filed by October 29, 1979.

Finally, parties are reminded that they may petition the Commission to amend its regulations in Part 290 at any time. The Commission's rules of practice and procedure regarding such petitions are codified in 18 CFR Part 1.

List of Parties that Submitted Comments

1. Detroit Edison Company
2. Dallas Power and Light Company
3. Texas Electric Service Company
4. Portland General Electric Company
5. Utah Power and Light Company
6. Southern Company Services, Inc., *et al.*
7. Tampa Electric Company
8. Pacific Power and Light Company
9. Puget Sound Power and Light Company
10. Electricity Consumers Resource Council
11. Minnesota Power and Light Company
12. Georgia Power Company
13. Association of Edison Illuminating Companies Load Research Committee
14. Alabama Power Company
15. Southwestern Public Service Company
16. Consumers Power Company
17. National Retail Merchants Association
18. Gulf Power Company
19. Iowa-Illinois Gas and Electric Company
20. Houston Lighting and Power Company
21. Florida Public Service Commission
22. National Consumer Law Center, Inc.
23. Central Maine Power Company
24. Salt River Project
25. Kansas City Power and Light Company
26. Tacoma Department of Public Utilities
27. Hawaiian Electric Company, Inc.
28. Arizona Public Service Company
29. Edison Electric Institute
30. Ohio Edison Company
31. Carolina Power and Light Company
32. Montana Power Company
33. Public Service Company of Colorado
34. Texas Power and Light Company
35. Washington Water Power Company
36. Northeast Utilities Service Company
37. Department of Energy
38. Illinois Power Company
39. Appalachian Power Company, *et al.*
40. New York State Electric and Gas Corporation
41. Missouri Power and Light Company
42. Iowa Southern Utilities Company
43. Arkansas Power and Light Company, *et al.*
44. National Association of Regulatory Utility Commissioners
45. North Carolina Utilities Commission
46. Public Service Electric and Gas Company
47. Baltimore Gas and Electric Company
48. Peninsula Power Company
49. Michigan Public Service Commission

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[74] Debevoise and Liberman, and Appalachian Power Co., *et al.*

50. Niagara Mohawk Power Corporation
51. Bangor Hydro-Electric Company
52. New York State Public Service Commission
53. Pennsylvania Power and Light Company
54. National Rural Electric Cooperative Association
55. Philadelphia Electric Company
56. Public Service Commission of Wisconsin
57. Debevoise and Liberman
58. Florida Power and Light Company
59. UGI Corporation, Luzerne Electric Division
60. GPU Service Corporation
61. City Public Service Board of San Antonio, Texas
62. American Public Power Association
63. Clark County School District, Las Vegas, Nevada
64. Public Service of Indiana
65. Central Power and Light Company, *et al.*
66. Public Utility District No. 1 of Snohomish Company
67. Massachusetts Electric Company, *et al.*
68. Northern States Power Company

(Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601–2645; Energy Supply and Environmental Coordination Act, 15 U.S.C. 791–798; Federal Power Act, as amended, 16 U.S.C. 792–828c; Department of Energy Organization Act, 42 U.S.C. 7101–7352, E.O. 12009, 42 FR 46267)

In consideration of the foregoing, the Commission is amending Part 290 of Chapter I, Title 18, Code of Federal Regulations, and is republishing Part 290 incorporating such amendments, as set forth below, effective October 29, 1979.

By the Commission.

Lois D. Cashell,
Acting Secretary.

[¶ 30,088]

44 F. R. 60080 (October 18, 1979)

18 CFR Part 2

[Docket No. RM80-1]

General Policy and Interpretations; Fuel Oil Displacement by Process and Feedstock Users

AGENCY: Federal Energy Regulatory Commission.

ACTION: Interim regulations.

SUMMARY: Federal Energy Regulatory Commission's (FERC) direct sale program for process and feedstock users of natural gas is expanded. Certificates of public convenience and necessity issued under this interim rule will permit participating process and feedstock users to use natural gas to the same extent as non-participating users. As a result, participating users will be able to displace the consumption of fuel oil with natural gas. Transporting pipelines may apply to amend existing certificates to reflect the provisions of the interim rule.

DATES: Written Comments by October 31, 1979.

EFFECTIVE DATE: October 5, 1979.

ADDRESS: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 (Reference Docket No. RM80-1).

FOR FURTHER INFORMATION CONTACT:

Robert C. Platt, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, 202-357-8454.

Robert D. Long, Office of Pipeline and Producer Regulations, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, 202-275-4382.

Before Commissioners: Charles B. Curtis, Chairman; Georgiana Sheldon, Matthew Holden, Jr., and George R. Hall.

Interim Rule

Issued October 5, 1979.

In the matter of Fuel Oil Displacement by Process and Feedstock Users, Docket No. RM80-1; Order No. 52.

I. Background

The Commission hereby issues an interim rule to amend the regulations establishing a direct sale program for process and feedstock users of natural gas (FPC Order No. 533 and FERC Order No. 2). Under these rules, prescribed in § 2.79 of the Commission's Regulations, high priority industrial users facing curtailment are permitted to obtain natural gas which otherwise would not be available to them. The proposed amendment herein would remove some of the end-use limitations presently incorporated in the FPC Order No. 533 and FERC Order No. 2 program.

The Commission's rule presently prevents process and feedstock customers who receive natural gas under Order No. 533 (Order No. 533 customers) from also receiving interstate system supplies for lower priority uses. This prohibition is of consequence for any Order No. 533 customer with both high priority and low priority loads (such as boiler fuel). The prohibition on low priority use of natural gas from system supplies applies regardless of the supplier's general level of curtailment. As a result, the low priority requirements of Order No. 533 customers are not served even when a supplier has sufficient natural gas to serve these requirements and is serving similarly low priority requirements of customers not receiving natural gas under Order No. 533. This constraint places the Order No. 533 customers at a disadvantage. The recent drop in curtailment levels [1] and the national need to displace fuel oil [2] makes these limitations inconsistent with the public interest. Accordingly, the proposed rule would eliminate these limitations and would permit customers to receive natural gas for low priority uses without jeopardizing their right to receive direct sale gas under Order No. 533.

A. Interstate System Supplies

Section 2.79(e) and (f) as amended by Order No. 2 presently limit the use of both system supplies and direct sale gas to two specified high priority uses. Only process uses (such as heat treatment) and feedstock uses (such as the production of ammonia from methane) are permitted.[3] At the time the Order No. 533 program was established in 1975, the system supplies of many interstate pipelines were so limited that many process and feedstock uses were facing imminent curtailment despite their high priority. Order No. 533 then represented a means of obtaining natural gas at unregulated prices, which was otherwise unavailable to the interstate market, for use in the interstate market. But Order No. 533 included end-use restrictions to prevent an Order No. 533 customer from meeting his low priority requirements at the expense of the high priority needs of other customers who rely upon interstate system supplies. The limitations of § 2.79(e) and (f) were intended to prevent disruption of supplies available to interstate pipelines and to allow unregulated natural gas to displace interstate pipeline supplies to the benefit of the other customers of the pipeline.

Two recent events permit the Commission to consider a relaxation of the paragraph (e) and (f) limitations. First, enactment of the Natural Gas Policy Act of 1978 (NGPA) has removed most of the distinctions between the intrastate and interstate markets. Second, the recent improvement in natural gas supplies on many interstate pipelines coupled with the current threat of a fuel oil shortage has prompted the Department of Energy (DOE) to encourage the use of natural gas instead of fuel oil where possible.

In response to a DOE proposal, on May 17, 1979, the Commission issued Order No. 30 which established procedures for the transportation of natural gas purchased by an end-user to displace fuel oil consumption during a fuel shortage emergency period.[4] As noted in Order No. 30, interstate system supplies are viewed by DOE as the first priority for fuel oil displacement:

> The Department will undertake two approaches to reduce imports in the near-

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[1] Protection of High Priority Natural Gas Consumers: The Emergency Authorities of the Natural Gas Policy Act of 1978. A Report to Congress by the FERC, issued June 1979, at 53, and Appendix C.

[2] Presidential Proclamation of a National Energy Supply Shortage of July 10, 1979.

[3] These uses are defined in § 2.78(c)(7) and (8).

[4] 44 F.R. 30323 (May 25, 1979).

> term through movement of surplus gas to oil users. The first approach is to encourage sales from producers or intrastate pipelines to interstate pipelines and distribution companies. Such sales will increase general system supply, thereby reducing overall gas curtailments and displacing fuel oil. The second approach is to encourage and facilitate the transportation of natural gas purchased directly from producers or intrastate pipelines by users capable of substituting gas for oil. In general, the Department's first priority is to encourage additions to interstate pipeline system supplies. However, when surplus gas in not fully utilized by interstate pipelines, the transportation of direct purchases will be facilitated.[8]

Because such uses of natural gas have already been authorized by outstanding contracts and certificates of public convenience and necessity, as well as by the normal operation of curtailment plans, this method of fuel oil displacement by those customers who do not receive Order No. 533 gas has occurred without additional Commission action. The proposed rule allows Order No. 533 customers to accept system supplies to displace fuel oil in the same manner as customers who do not receive gas under Order No. 533. As a result, the interim rule permits Order No. 533 customers to displace fuel in these circumstances without prior certification from the Economic Regulatory Administration.

B. FERC Order No. 30 Direct Sales for Fuel Oil Displacement

A similar problem arises in the case of Order No. 533 customers who wish to obtain additional natural gas to displace fuel oil through the direct sale program established by Order No. 30. These fuel oil users are prohibited from using natural gas for other than process and feedstock uses by limitations imposed in § 2.79(e) and (f) and by conditions attached to the certificate of public convenience and necessity which authorizes the transportation of direct sale gas to the Order No. 533 customer. The interim rule would modify these limitations and also would permit Order No. 533 customers to purchase natural gas under Order No. 30 for those low priority uses which have been certified by the Economic Regulatory Administration as displacing fuel oil.

C. Related Issues

The interim rule does not attempt to resolve all of the issues raised by direct sales to process and feedstock users. The Commission intends to address many of these issues in the pending adjudication in Docket No. CP77-71 and in a direct sale program for "essential industrial process or feedstock uses" accorded a high curtailment priority under section 402 of the NGPA.

II. Summary of Rule

The interim rule adds four new paragraphs to § 2.79 of the Commission's Regulations.

A. Transitional Rules

The interim rule would not alter the conditions contained in outstanding Order No. 533 certificates. Instead, the Commission intends that the policy outlined in this rule would be automatically incorporated into certificates issued after the effective date of the interim rule. Under paragraph (k) any pipeline seeking to amend its outstanding certificates issued pursuant to Order No. 533 and Order No. 2 may make a one-time blanket filing with the Commission. The Commission will consider the application on an expedited basis, and has delegated approval of such amendments to the Director of the Office of Pipeline and Producer Regulations in § 3.5(f)(iv) of this chapter.

Paragraph (l)(1) states the Commission's intention to incorporate paragraph (m) as a condition in certificates issued after the effective date of the interim rule. The Commission's policy of limiting volumes transported under an Order No. 533

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[8] Statement of James R. Schlesinger dated March 13, 1979 at 2.

certificate to a customer's process and feedstock requirements is continued in paragraph (l)(2).

Paragraph (m) defines the volume of natural gas that an Order No. 533 customer may purchase from either his supplier or through direct sale. Paragraph (m) is intended to lift many of the restrictions previously imposed by paragraphs (e) and (f). The restrictions are now framed in terms of aggregate volumes to give the customer flexibility in meeting its requirements. Unlike the terms of paragraph (f), the Order No. 533 customer may now vary the proportion of total natural gas supplies that are purchased from its supplier or in direct producer sales.

Paragraph (m) classifies the customer's aggregate supplies into two volumes. The "normal entitlement" represents the volume of natural gas which the customer would have received under the supplier's curtailment plan if the customer was not an Order No. 533 customer. Any aggregate supplies in excess of the normal entitlement are permitted only in three specific cases.

B. Use of System Supplies

Paragraph (m)(1)(i) provides that the customer is not disqualified from purchasing its normal entitlement from the supplier by reason of any condition in a certificate issued pursuant to this section.[6] The only restriction is that the customer's aggregate supply volume (including direct purchases) may not exceed the limit specified in paragraph (m)(2).

C. Use of Direct Sale Gas

Due to the recent improvement in natural gas supplies, an Order No. 533 customer frequently receives less aggregate supplies than would be otherwise available to the customer in the absence of participation in the Order No. 533 program. Paragraph (m) removes three previous restrictions from the Order No. 533 customer and thereby puts him on a par with customers that do not receive natural gas under Order No. 533. First, paragraph (m)(1)(ii) does not impose an end-use restriction upon the customer's Order No. 533 gas. Given the volumetric limitations upon a customer's aggregate supplies in paragraph (m)(2), end-use restrictions are no longer required.

Second, paragraph (m)(2)(ii)(A) permits the Order No. 533 customer to receive the maximum daily volume authorized in the certificate if the customer's aggregate supplies do not exceed the normal entitlement. In other words, the mix of direct purchase and system supply volumes is left to the customer; the Commission will be concerned only with the total volumes consumed from all sources.

Second, during periods of deep curtailment, a customer's normal entitlement may drop below the customer's high priority requirements. The Order No. 533 program was designed to protect process or feedstock uses in these circumstances. Paragraph (m)(2)(i) continues to provide a means of protecting against curtailment of the customer's high priority requirements. Prior to the interim rule, only the requirements described in paragraph (a) were so protected. The interim rule expands the category of requirements eligible for this protection to reflect the new curtailment priorities created by Title IV of the NGPA. These requirements are defined as "high priority requirements" in paragraph (n)(3).

In addition, paragraph (m)(2)(ii)(B) increases the normal entitlement ceiling by adding the volume of fuel oil displacement gas certified by the Economic Regulatory Administration under the Order No. 30 program (Subpart F of Part 284). This paragraph should also remove any doubt that Order No. 533 customers are eligible to participate in fuel oil displacement transactions under Order No. 30. Because the paragraph (m)(2) test is made on an aggregate volume basis, the customer may meet eligible fuel oil displacement requirements with natural gas purchased from a producer under Order No. 533. Upon the expiration of the Order No. 30 program, the ceiling on aggregate supplies would revert to the normal entitlement volume.

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[6] In contrast, under paragraph (f), an Order No. 533 customer was previously required to reduce the volume purchased from its supplier so that the customer's aggregate supplies did not exceed the customer's process and feedstock requirements.

Paragraph (m)(2)(ii)(C) clarifies the relationship between this direct sale program and the direct sale program created for essential agricultural uses by Order No. 27 (Subpart E of Part 157). Participation in the Order No. 533 program does not disqualify a customer from participating in Order No. 27 transactions. Volumes received under Order No. 27 are simply included in the customer's aggregate supplies and remain subject to the terms and conditions specified in Order No. 27.

III. Effective Date

These regulations are being issued effective immediately on an interim basis, because the Commission finds that the need to promote immediate displacement of fuel oil constitutes good cause to find prior notice and public procedure to be impracticable and to waive the thirty day publication requirement. The Commission requests data, views or arguments with respect to these regulations. After evaluating the information received, the Commission will make any appropriate revisions to these regulations.

IV. Written Comment Procedures

Interested persons are invited to submit written comments, data, views or arguments with respect to this proposal. An original and 14 copies should be filed with the Secretary of the Commission. All comments received prior to October 31, 1979, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, 825 North Capitol Street, N.E., Washington, D.C., during regular business hours. Comments should be submitted to the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should reference Docket No. RM80-1.

(Natural Gas Act, 15 U.S.C. § 717, *et seq.*; Public Utilities Regulatory Policy Act of 1978, Pub. L. 95-617; Department of Energy Organization Act, 42 U.S.C. § 7101, *et seq.*, E.O. 12009, 42 FR 46267)

In consideration of the foregoing, the Commission amends Part 2, Subchapter A, of Chapter I of Title 18, Code of Federal Regulations, as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,089]

44 F. R. 60083 (October 18, 1979)

18 CFR Part 154

[Docket No. RM79-22]

Natural Gas; Order Amending Regulations Relating to Evidentiary Submissions and Extending Deadlines for Filing of Third-Party Protests

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Amendment to final regulations.

SUMMARY: The regulations are amended to delete the requirement that third-party protests be served on each affected producer who may be a party to the contract in issue. The third-party protest must, however, in all cases be served on the affected interstate pipeline. The pipeline shall mail a copy of such protest to the producer who is the other party to the contract. The regulations are further amended to extend the deadline for the filing of third-party protests to 60 days after the

date that the evidentiary submission regarding the contract was filed with the Commission.

EFFECTIVE DATE: October 11, 1979.

FOR FURTHER INFORMATION CONTACT: Mark Magnuson, Office of the General Counsel, Federal Energy Regulatory Commission, Room 4016–G, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357–8511.

SUPPLEMENTARY INFORMATION: Amendment and clarification of the Commission's interim regulations Implementing the Natural Gas Policy Act of 1978 and regulations under the Natural Gas Act, Docket No. RM79–22. October 11, 1979.

Sections 154.94(h)(8), and 154.94(i)(3)(i)(B) of our regulations set forth the service requirements that must be met for interested parties to protest an assertion that a natural gas purchase contract contains the requisite contractual authority under the Natural Gas Act (NGA) for the producer to charge and collect the applicable maximum lawful price under the Natural Gas Policy Act of 1978 (NGPA). Among other things, these regulations require that any third-party protest, i.e., and protest by a party who was not a party to the contract, must be submitted to the Commission, the pipeline/purchaser, and the producer/seller.

On September 21, 1979, a Petition of Third-Party Protesters for Waiver of Service Requirements was filed by a group of potential third-party protesters (petitioners).[1] Petitioners request that the Federal Energy Regulatory Commission (Commission) waive the requirement that each protest be served on the affected producer.

Petitioners object to this requirement for two reasons. First, it is alleged that petitioners do not have reasonable access to the addresses of all the producers who may be a party to the contracts which may be protested. Second, even if the addresses were made available, petitioners allege that the expense of providing service of the protests to the producers is prohibitive. As an alternative to requiring third-party protesters to submit the protests to the producers, petitioners suggest that adequate notice could be given to producers either through publication in the **Federal Register** or by service by the pipeline.

Indicated Producers filed an answer to this petition on October 2, 1979. Indicated Producers urge in their answer that the service requirement not be changed. However, it is suggested that the pipelines should be required to provide, to any interested party, the address of each producer mentioned in the pipeline's evidentiary submission. Further, Indicated Producers state that they have no objection to a short extension of the deadline for the filing of third-party protests, in order to afford adequate time for the third-party protester to receive the addresses and serve the producer.

The Commission believes that both of the objections raised by petitioners are well founded, and that unless they are eliminated, the protest procedure established in Order No. 23–B could not be meaningfully utilized by interested parties. Further, we disagree with Indicated Producers that adequate notice to producers can only be afforded through mailed service by the third-party protester. We believe that adequate notice will be given to the producers by publication in the **Federal Register**. Accordingly, we shall amend our regulations to delete the requirement that third-party protests be served on producers. However, such protests must in all cases be served on the affected interstate pipeline. In order to provide additional assurance that the producers are given notice of the filing of a third-party protest, we shall further require that upon receipt by a pipeline of any third-party protest, such pipeline shall mail, within 30 days to the other party to the contract, the producer/seller, a copy of such protest.

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[1] Associated Gas Distributors, Pacific Gas and Electric Company, Public Service Commission of the State of New York, Kansas Corporation Commission, Arizona Corporation Commission, Gas Consumers Group, Winfield, Kansas, Mangum, Oklahoma, State of Michigan, Michigan Public Service Commission, Congressman Andrew Meguire South Dakota Public Utilities Commission, Southern California Gas Company, Memphis Light, Gas and Water Division, Wisconsin Public Service Commission, Minnesota Public Service Commission, and Public Utilities Commission of the State of California.

We also note that if the third-party protest meets the burden of coming forward and a hearing is ordered, the producer and the pipeline will be provided with mailed notice of that hearing.

Further, the Commission has determined that the deadlines for the filing of third-party protests should be changed. The present rule sets the deadline at 120 days from the date of the blanket affidavit or interim or retroactive collection filing, or at a specified date, whichever is later. Evidentiary submissions are required to be submitted 60 days after such filings, but many pipelines have received extensions of this deadline.

To afford adequate time for third-party protesters to examine the evidentiary submissions of the pipeline, the deadline for filing third-party protests will be extended to 60 days after the date that the evidentiary submission regarding the protested contract was filed with the Commission. This deadline will supercede the deadlines which have previously been indicated.[2]

The amendments contained herein were developed in consideration of petitioners' comments, as well as the answer of Indicated Producers and all of the comments generated by the orders and notices issued in Docket No. RM79-22. Accordingly, the Commission finds that further notice and public procedures on these amendments are unnecessary and impracticable, and that good cause exists to dispense with additional notice and opportunity to comment. Further, we find good cause for the amendments in the regulations contained in this order to be effective immediately, in light of the fact that deadline for filing many third-party protests is October 15, 1979.

(Natural Gas Act as amended, U.S.C. 717, *et seq.*; Department of Energy Organization Act, 42 U.S.C. 710, *et seq.*, E.O. 12009; 42 FR 46467; Natural Gas Policy Act of 1978, 15 U.S.C. 3301 *et seq.*)

In consideration of the foregoing, Part 154 of Subchapter E, Chapter I, Title 18, Code of Federal Regulations, is amended as set forth below.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,090]

44 F. R. 61327 (October 25, 1979)

18 CFR Parts 2 and 271

[Dockets Nos. RM79-19 and RM79-12; Orders Nos. 45 and 31-A)

Treatment of Certain Production-Related Costs for Natural Gas To Be Sold and Transported Through the Alaska Natural Gas Transportation System; Statement of Policy; Order Granting Rehearing for the Purpose of Further Consideration and Order Staying Effective Dates

October 19, 1979.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Order staying effective dates.

SUMMARY: On August 24, 1979 the Commission issued two orders, both to be effective on October 23, 1979. The first, Order No. 45 (issued under Docket No. RM79-19) (44 FR 51554, September 4, 1979) amended Commission regulations under the Natural Gas Policy Act and

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[2] The petitions for extension of time that have been filed which have not requested extensions beyond 60 days after the filing of the evidentiary submission are thus rendered moot by this order.

provided a policy statement under the Natural Gas Act. Both regulations and policy statement addressed the issue of producer responsibility for production-related costs incurred in first sales of natural gas produced at Prudhoe Bay, Alaska for transport through the Alaska Natural Gas Transportation System. The second, Order No. 31–A (issued under Docket No. RM79–12) (44 FR 41081, September 4, 1979) implemented the policy of Order No. 45. Petitions to rehear both orders have been received. In addition, the Secretary of Energy has requested rehearing to permit certain actions by the Department of Energy which will relate to Order No. 45. For these reasons, the effective date of both orders is stayed.

DATE: Effective dates of Order No. 45 and Order No. 31–A stayed until December 5, 1979.

FOR FURTHER INFORMATION CONTACT: John Conway, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8100K, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357–8150.

SUPPLEMENTARY INFORMATION:

Treatment of certain production-related costs for natural gas to be sold and transported through the Alaska Natural Gas Transportation system, Docket No. RM79–19; Determination of incentive rate of return, tariff and related issues, Docket No. R78–12.

On September 21, 1979, the Altantic Richfield Company, the Sohio Natural Resources Company, and the Phillips Petroleum Company filed separate applications for rehearing of Order No. 45, issued on August 24, 1979, under Docket No. RM79–19 and Order No. 31–A issued on August 24, 1979 under Docket No. RM78–12. On September 24, 1979, the State of Alaska and the Exxon Corporation also filed separate applications for rehearing of Order No. 45 and Order No. 31–A. The applications for rehearing raise various issues regarding the lawfulness and appropriateness of the actions taken by the Commission in Order No. 45 and Order No. 31–A.

On October 15, 1979, The Commission was informed by letter from the Secretary of Energy, that the Secretary is holding discussions with North Slope producers for the purpose of involving them in the financing of the Alaska Natural Gas Transportation System (ANGTS). That letter stated that a formal filing by the Department of Energy reflecting the impact of producer financing commitments on Order No. 45 will be made in Docket No. RM79–19 and requested rehearing to reconsider Order No. 45.

In response to the request of the Secretary of Energy and to conclude deliberations of the issues raised in the applications for rehearing, the Commission finds good cause to grant rehearing of Orders 45 and 31–A for the purpose of further consideration. Given the statutory directive of section 9(a) of the Alaska Natural Gas Transportation Act, 15 U.S.C. 719g(a), that actions necessary or related to the construction and initial operation of the ANGTS must be accomplished at the earliest practicable date, the Commission further finds it appropriate to stay the effective date of Ordering Paragraph (1) of Order No. 45 and the effective date of Ordering Paragraph (B) of Order No. 31–A until a fixed date, December 5, 1979.[1]

The Commission orders: (A) The applications for rehearing filed by Atlantic Richfield Company, Sohio Natural Resources Company, Phillips Petroleum Company, the State of Alaska, and Exxon Corporation are hereby granted for the limited purpose of further consideration. As provided by Section 1.34(d) of the Commissions's Regulations, no answer to the applications will be entertained by the Commission since this order does not grant rehearing on any substantive issues.

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[1] This order does not apply to Orders 31 and 31–B, issued under Docket No. RM78–12. Orders 31 and 31–B are final orders not in effect.

(B) Ordering Paragraph (1) of Order No. 45, issued August 24, 1979, under Docket No. RM79-19 and Ordering Paragraph (B) of Order No. 31-A, issued on August 24, 1979, under Docket No. RM78-12 are stayed until December 5, 1979.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,091]

44 F. R. 61328 (October 25, 1979)

18 CFR Parts 4, 16, and 131

[Docket No. RM79-23; Order No. 54]

Water Power Projects; Final Regulations Prescribing General Provisions for Preliminary Permit and License Applications and Final Regulations Governing Applications for, Amendments to, and Cancellation of Preliminary Permits

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Commission is amending parts of its regulations governing preliminary permits and licenses under Part I of the Federal Power Act. The regulations amended in this docket prescribe technical filing requirements and evaluation procedures applicable to both preliminary permits and license applications for water power projects. The amendments also affect regulations pertaining to the content of preliminary permits, amendments to preliminary permits, and cancellation of preliminary permits. This rulemaking is part of the Commission's reform of water power project licensing and extends the benefit of section 405 of the Public Utility Regulatory Policies Act of 1978, requiring simple and expeditious licensing procedures for small (15 MW of installed capacity or less) hydroelectric power projects, to all such projects within the Commission's jurisdiction.

The amended regulations reorganize and clarify the permit and license application procedures and thereby help to ease the burden of compliance. The changes will therefore facilitate hydroelectric development.

EFFECTIVE DATE: November 26, 1979.

FOR FURTHER INFORMATION CONTACT:
James Hoecker, Office of Regulatory Development, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8161.

SUPPLEMENTARY INFORMATION:

Regulations Prescribing General Provisions for Preliminary Permit and License Applications; Regulations Governing Applications for, Amendments to, and Cancellation of Preliminary Permits; Final Rule.

Issued: October 22, 1979.

Notice is hereby given that the Federal Energy Regulatory Commission (Commission) is amending certain of its regulations concerning preliminary permits and licenses for water power projects under Part I of the Federal Power Act (Act). The amended regulations prescribe technical filing requirements and evaluation procedures applicable to both preliminary permit and license applications. The amendments also affect the regulations pertaining specifically to the content of preliminary permit applications, amendments to preliminary permits, and cancellation of preliminary permits.

I. Background

Seeking to respond and lend encouragement to the recent heightened interest in hydroelectric development, Congress provided in Title IV of the Public Utility Regulatory Policies Act (PURPA) component of the National Energy Act for a program whereby the Secretary of Energy will grant loans for feasibility studies and for construction of small hydroelectric projects (installed capacity of 15 MW or less) located at existing dams. The Commission is charged under section 405 of PURPA with establishing simple and expeditious licensing procedures for projects eligible under the PURPA provisions.

In the interest of acting more promptly on all license applications, and in anticipation of the enactment of PURPA, the Commission determined in 1978 to carry out a thorough reform of its requirements and procedures for license applications. The first phase of this reform was instituted in September 1978, with issuance of a rulemaking on the so-called "short-form" license procedures applicable to all "minor" projects (installed capacity of 1.5 MW or less). [See Order No. 11, Docket No. RM78–3, 43 FR 40215 (September 11, 1978).]

The second phase of the reform covers all "major" projects (installed capacity greater than 1.5 MW) where at least a dam and reservoir are in existence at the time of the application. The Commission issued a Notice of Proposed Rulemaking on this phase on April 19, 1979 [44 FR 24095, April 25, 1979]. A third and final phase will cover all major projects which include new dams and reservoirs.

The revisions contemplated in this three-stage reform pertain primarily to the content of license applications. Maximum efficiency cannot be attained, however, unless the uncertainty regarding such technical and procedural matters as form, subscription and verification, service, number of copies, correction of deficiencies, and evaluation of competing applications is eliminated. Therefore, the Commission issued a Notice of Proposed Rulemaking in this docket to clarify and streamline the general provisions governing these requirements and procedures for all preliminary permit and license applications. [44 FR 12432, March 7, 1979.]

These regulations make the Commission's technical filing requirements and procedures easier to identify and comprehend. The regulations also make clear that diligence is expected of initial applicants and those who would file competing applications, as well.

A well-rounded program of licensing reform must also reach the specific requirements governing preliminary permits. As enunciated in sections 4(f) and 5 of the Act, 16 U.S.C. 797(f) and 798, the purpose of a preliminary permit is to secure for the permittee priority of application for a license for a project while the permittee obtains the data and performs the acts required to determine the feasibility of the project and support an application for a license. A preliminary permit is not a prerequisite to a license, and therefore is sought on a voluntary basis. The protections afforded by permits result in frequent permit applications, however. In view of the relationship between preliminary permits and licenses, this docket also covers revised regulations concerning the substance of preliminary permit applications, amendments to preliminary permits, and cancellation of preliminary permits.

The revised regulations require sufficient information to enable the Commission to carry out its responsibilities under the Act. The regulations also make clear the purpose of a permit and the consequences of failure to carry out that purpose. These changes should further facilitate ultimate licensing of small hydroelectric projects at existing dams, in accordance with section 405 of PURPA.

II. Comment Analysis

This rulemaking was commented on by five agencies of Federal, State, or local government, two environmental organizations, five utilities or trade associations, and one supplier of hydroelectric equipment. The commenters expressed overall support for the simplified procedures for applying for preliminary permits and licenses. Comments and suggestions regarding specific provisions and the Commission's treatment of the comments are as follows:

"Minor part" licenses that were issued in the past had been based upon an erroneous conclusion of law concerning Commission jurisdiction, which the Commission had repudiated. [*See, e.g., Pacific Gas and Electric Co.*, Project No. 2310, 29 F.P.C. 1265 (1963).] To the extent that an application is now filed for only a part of a whole project, of "complete unit of development," (*e.g.*, a power plant to be added to a Corps of Engineers' dam), it would be filed according to its category under our application regulations. Since the application regulations depend on the installed capacity of the facilities proposed to be licensed and on whether any new dam or significantly larger impoundment would be created—not on whether only a part of the whole project need be licensed—references to "minor part" licenses in the application requirements are unnecessary. Therefore, "minor part" language will not be added to § 4.31(a)(2) as requested in the comment of the Power Authority of the State of New York (PASNY).

It was suggested that § 4.31(c)(4) of the proposed regulation, which describes one of the steps to be taken by the Commission upon receipt of an acceptable application for preliminary permit of license, be made more specific in terms of notification and effective date requirements for reserving Federal lands. The Commission believes that greater detail in explaining procedures which are essentially matters of internal agency management, such as details on notification of withdrawal of Federal land or inclusion of processing flowcharts in the rule, would only serve to lengthen and complicate the regulation with no significant benefit to applicants, intervenors, or the public.[1] Related comments state that since the regulations impose filing deadlines for deficient and competing applications, the Commission should likewise impose deadlines on its staff to assure that an applicant does not lose a priority status or a chance to compete for a project license because of staff inaction. Since these are regulations primarily informing applicants of their rights and responsibilities, those kinds of directions to the Commission staff are beyond their scope. The Commission has adopted, and will continue to seek to develop, internal procedures for more expeditious handling of applications. In any event, it is important to remember that time constraints imposed on applicants, such as that in § 4.31(d), do not run until the applicant is notified of deficiencies in an application. The time expended in reviewing an application for deficiencies will not, therefore, adversely affect the applicant's time to cure deficiencies. If deficiencies are cured within the prescribed time, § 4.31 provides that the application will be deemed accepted for filing as of the original date the application was submitted.

Some commenters suggested that applicants could be prejudiced by greater use of "summary rejection" by the Commission's delegate, without an explanation of the reason for rejection. The regulations were not intended to call for greater use of summary rejection than before. Moreover, when an application is rejected, an applicant is always provided with the reasons for such action, as suggested. The proposed regulation has been revised to make these points clear. In addition, an applicant may request extensions of time under § 1.13(d) of the regulations or appeal actions of the staff to the Commission under § 1.7(d). These procedural safeguards help assure that the burden on the applicant is no greater than necessary for a thorough disposition of each case.

Section 4.31(d) provides a 90-day period for correcting deficiencies in license applications (45 days for permit applications). Many commenters thought that this period should be extendable for good cause. We point to § 1.13(d) as providing this flexibility. In answer to other comments, pending applications that meet the requirements of our prior regulations, but not those of the new rule, will not be rejected. The new regulatory scheme anticipates requests for added information and provides procedures in § 4.31(f) for securing remaining data required for such pending applications. American Electric Power Service Corporation expressed a desire that the regulations more clearly spell out the criteria for an acceptable application. We think that the regulations as presented provide sufficient guidance and information for the applicant in terms of content, format and submittal requirements. Where a prospective applicant has questions, it may seek guidance from the staff under § 4.31(g).

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[1] Any person who desires information on the nature of the Commission review processes may consult the critical Projects Status Reports ("Orange Books") available at the Commission's Office of Public Information which show, among other things, typical processing flowcharts for license applications. Copies of these Reports may also be purchased from the Government Printing Office.

The proposed § 4.31(f) provided that the Commission may request additional information deemed "necessary or desirable to process the application." This provision had no subject matter limit. Commenters found fault with the provision because it was too vague or because mere desirability appeared to be too broad a standard. Although it cannot be indicated with any specificity what the additional information might consist of in any single instance, the language has been changed to clarify that the Commission may require additional information considered "relevant for an informed decision on the application."

Minnesota Mining and Manufacturing Company proposed various technical changes in § 4.32, regarding specifications for maps and drawings. Three proposals were adopted in the final rule. In § 4.32, originals of maps and drawings must be prints on silver "or gelatin" 35mm microfilm mounted on Type D aperture cards, the measurements of which are corrected to 3¼ inches x 7⅜ inches. The commenter suggested a different range of sizes for full-sized prints and the incorporation of other specifications according to certain documents of the American National Standards Institute. The Commission will retain the sizes expressed in the proposed rule because they have become standard for applicants and consultants. However, waiver may be obtained pursuant to § 1.7(b) of the regulations in appropriate circumstances. Other suggested specifications may prove to be too technical for small developers. In § 4.32(d), the reduction standard to 10.5 inch prints is changed to 11 inches, as suggested.

PASNY suggested that the § 4.32 map scale of 1 inch equals 1,000 feet is unrealistic and should be at least 1":2000'. Experience shows that maps of project works require varying degrees of detail, depending on the facilities being described. Paragraph (b) is revised to provide that maps of transmission lines, roads, or other linear features may be drawn on a scale not smaller than 1 inch equals one-half mile. This enables the applicant to use, without enlargement, Forest Service or Bureau of Land Management maps, as well as United States Geological Survey maps, for the less detailed features of a project. Maps covering the other project features, however, must be no smaller than 1 inch equals 1,000 feet. A smaller scale would not be sufficiently detailed for proper evaluation of the non-linear features. In instances where maps at these scales do not show sufficient detail, larger scale maps may be required as an additional submission. Section 4.81(e) provides that maps for preliminary permits need not adhere to the scale required by § 4.32(b) if they are legible at a smaller scale.

The Rural Electrification Administration (USDA) proposed that § 4.33(a) specify that notices of an application state the time allowed for filing competing applications. Such notices will include such information, but it is not necessary that § 4.33(a) so state. The suggestion that rural electric cooperatives and appropriate non-profit organizations be given the same preferential status as that accorded municipalities or states in § 4.33(f) must be left for Congressional action, because the state/municipal preference is embodied in section 7 of the Act. Similarly, the proposal by Allis-Chalmers corporation that the Commission not accept an application by a U.S. corporation if a majority of the stock is foreign-owned would narrow section 4(e) of the Act and must be left for Congressional action.

Pacific Gas and Electric Company (PG&E) advocates changing the "reasonable period of time" that would be provided under § 4.33(f)(4) for a state or municipality to make its plans as well adapted as a non-preference applicant's plans. Instead, PG&E proposes a specific maximum of 90 days plus one extension for good cause. Although the PG&E proposal has some merit, a suitable period for adapting plans may vary from case to case, and even less than 90 days may be reasonable in many instances. Accordingly, the Commission believes it preferable to retain the case-by-case approach reflected in the proposed regulation.

In accordance with the comments of the American Electric Power Service Corporation (AEP) and Santa Clara, California, § 4.33(c) has been altered to provide more time (120 days) for the filing of competing license applications. This recognizes the greater complexity of license, as opposed to preliminary permit, applications and the difference in time required for suitable preparation as a consequence.

Both the Sierra Club and the American Electric Power Service Corporation believe that § 4.34 permits too much Commission discretion in ordering hearings on preliminary permits. The former suggests that the rules specify that hearings be held anytime there is a substantial environmental controversy, while the latter views competing applications as the only valid ground for hearing. The Act does not require hearings on preliminary permit applications, and the purpose of an evidentiary hearing would be to explore material issues of fact that might arise in a proceeding. Since there is no way to delimit in advance the material issues of fact that might arise with respect to any particular permit application, the Commission will retain the provision as stated in the proposed rule.

Several environmental concerns were expressed by the Sierra Club and the National Wildlife Federation (NWF). Sierra Club recommends that this rule be integrated with the Commission's regulations under the National Environmental Policy Act because of the close relationship between processing of preliminary permits and licenses and the environmental review process. The Commission's proposed regulations implementing NEPA were issued in Docket No. RM79-69 on August 20, 1979. That rulemaking was drafted with specific attention to this rulemaking and related water power project licensing reforms. In carrying out the objectives of NEPA, the Commission has taken steps to assure that relevant environmental considerations are reviewed during the appropriate stages of the permitting and licensing processes. However, environmental issues are only a portion of the concerns addressed in these processes. The proposed NEPA regulations apply so broadly to Commission functions and activities of regulated entities that incorporation of related substantive provisions would result in an unnecessarily complicated package. Therefore, the regulations are being promulgated separately.

NWF expressed the opinion that the issuance of a permit commits an applicant to the chosen site and creates an inexorable momentum toward licensing that will undermine environmentally preferable options. We do not believe that the grant of a permit and the financing of feasibility studies commits an applicant—and certainly not the Commission—to a specific site, to the exclusion of alternative sites. Moreover, the investments and studies made by a permittee could be made even without a permit. (However, the Commission agrees that examination of possible alternative project sites must begin early in the overall processes, while the permit is in effect, as discussed below.) The permit mechanism allows early monitoring of applicants' activities, which would not be possible if a prospective license applicant did not seek a permit. Review of alternatives is more properly part of the licensing process, after a permittee has determined whether it will even pursue a specific project.[2]

The comments of the Sierra Club reflect a view similar to that of NWF, that permit applications should contain an explication of alternatives, including discussion of environmental costs and conservation alternatives. While the studies conducted under a permit and reported under § 4.81 would be used to support any license application, it is the license application itself that must supply the substantive economic and environmental information upon which the Commission decides to approve or disapprove a project. Section 4.81 does not, therefore, require the kind of detailed presentation of alternatives which the commenter desires. Under § 4.81, an applicant is required to describe the studies it proposes and, where new dam construction is involved, a work plan and schedule. The permits themselves contain standard conditions which require permittees to assess the impact of each project and feasible alternatives and to prescribe the types of studies to be conducted under the permit. The conditions imposed on permittees may vary, but the following Article 7 has essentially become standard in preliminary permits, in addition to the Articles in Form P-1 (revised October 1975):

> *Article 7.* Permittee, in the interest of protecting and developing the natural resources and other environmental values of the project area, shall consult with the appropriate federal, state, and local agencies in their fields of responsibility and expertise, shall conduct its project investigations in a manner which protects the environmental integrity of the area, *and shall fully explore all feasible alternatives to the project, and alternative project designs, taking into account impacts on natural resources and other environmental values.* These resources and values include, but are not limited to: forests; land management and treatment; fish; wildlife; recreation and public use; water and air quality (including water supply, ground water, waste treatment and disposal); public health and safety; archeology; historic and cultural sites; threatened or endangered species of flora and fauna; potential wild, scenic, or recreational river designation; and scenic and aesthetic values. The permittee shall initiate and conduct or have conducted such studies as may be necessary to determine the impact of the construction and operation of the proposed project on these natural resources and values and measures needed to protect and develop them or to provide for their mitigation or replacement, including alternative designs and operational measures, and shall utilize the results of such studies in the preparation of Exhibits, H, R, S, V, and W to accompany any application for a license to construct and operate the project. In connection with studies pertaining to archeological, historic, and cultural sites, the permittee shall consult with the State Historic Preservation Officer and the Heritage Conservation and Recreation Service of the U.S. Department of the Interior. (Emphasis added)

The Sierra Club advocates promulgation of such conditions in this rulemaking. This rulemaking, however, encompasses application requirements and processing of preliminary permits, not the proper standard permit conditions. However, the standard conditions in Form P-1 are a matter of public record, as are other conditions typically included in permits. Compliance with the permit conditions enables the permittee to supply more detailed environmental information to the Commission when applying for a license. Foresighted permittees would, of course, assess alternatives as early as possible, even before applying for a permit. But it would go far beyond the purpose and usefulness of preliminary permits to require examination or specification of a specified number of alternatives before the permit is filed or granted.[3] The permit stage is not intended to serve as a forum for resolving all questions relating to the appropriateness of a project. Indeed, such requirements could simply induce developers to avoid seeking permits.

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[2] Studies under permits have often found projects infeasible for environmental, technical, or economic reasons. *E.g.*, Marble Valley Project No. 2679, Stony Creek Project No. 2719, and Canaan Mountain Project No. 2706.

[3] An applicant that knows of a reasonable alternate site before filing for a preliminary permit and seeks no permit for the alternative site runs the risk of having no priority for what may prove to be the better site.

Although we believe that environmental reporting requirements should not become unrealistically burdensome at the preliminary permit stage, particularly for developers of small hydroelectric projects, the concern expressed by the Sierra Club that certain information be elicited regarding the potential environmental impacts of activities conducted under the permit is well-founded. Exhibit 2 (§ 4.81(c)) has been revised to distinguish between those projects or developments within projects that would invove dam construction that will necessitate such geological exploration as test pits or boring and those that will not. Applicants for projects that would require new dam construction must file, in addition to a study plan, a work plan and schedule of proposed field studies, and measures to be taken to minimize any environmental disturbances or to restore altered or disturbed areas. This requirement may be waived under specified circumstances.

The extent of the information required of permit applicants—descriptions of the projects, study plans, work plans, and work schedules—should always be commensurate with the scope of any proposed new development. The Commission also retains discretion under § 4.31(f) to require additional necessary information relevant to the activities to be undertaken under the permit, including the environmental impact. Information on the environmental impact of actually constructing and operating a project is premature at the preliminary permit stage and belongs in the license application, assuming that the permittee decides to seek a license.

At the suggestion of NWF, Exhibit 4 has been revised to require application maps to show areas being included or studied for inclusion in the National Wild and Scenic Rivers System and the National Wilderness Preservation System.

Edison Electric Institute indicated that the regulations fail to specify when preliminary site investigation ends and construction begins. Construction may not occur during the permit period, and may not begin until the actual license is issued. The ban on construction prior to the issuance of a license is mandated by section 23(b) of the Act.

AEP, citing the *Pacific Northwest Company* case, 31 F.P.C. 247, 265, points out that the developer's conception of a project may change during the permit period as studies proceed. AEP appears to believe that the proposed rule would narrow the scope of the permit and affect the resulting priority. Moreover, AEP and some other commenters believe that the proposed rule requires applicants to provide too much detailed information that is unavailable at the time one applies for a permit. These regulations, however, affect the content of a permit application and not the scope of the permit. Preliminary permit applications should be prepared broadly enough to accommodate some variations in the original concept of the project. If necessary, the permittee may seek an amendment of the permit under § 4.82. In any event, there are two basic principles for providing information in applications: the permit applicant must inform the Commission of project details "to the extent possible" and commensurate with the scope of the project. While applicants are hopefully not dissuaded from availing themselves of new ideas developed during the permit period, they should also be encouraged to refine their ideas before applying for a permit. The maximum three-year term of a permit should not be viewed as a time for random experimentation.[4] The exhibits in § 4.81 therefore require an applicant to file sufficient information to demonstrate the credibility of its proposal before a priority status is granted.

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[4] In the interest of more expeditious licensing procedures for water power projects, the Commission will consider a proposed rulemaking or statement of policy that will limit the term of preliminary permit for certain projects, based on the size of the project or the kind of construction involved. The Commission has descretion to issue permits less than three years in duration, under section 5 of the Act.

The information on proposed power sales required at the permit stage in § 4.81(d)(3) [Exhibit 3] was alternately called too general or unnecessary. A general idea of the available market for the new power is basic even to the preliminary consideration of a project and should be available by the time a permit application is filed. On the other hand, it would be premature to provide, and unreasonable to expect, such information in great detail this early in the consideration of a project.

Southern California Edison Company contends that the provisions of § 4.33(f)(4), giving states and municipalities an opportunity to make their plans as well adapted as the plans of a non-public applicant, contravenes section 7 of the Act. On the contrary, section 7(a) itself requires that the Commission fix a reasonable time for a state or municipal applicant to make its plans "equally well adapted" as those in an application filed for the same site by a non-public applicant. We do not believe that a state or municipal applicant can have a realistic opportunity to render its plans "equally well adapted" until the Commission has first found that those plans are not as well adapted and has stated why.

The provision in existing § 4.31(a) allowing incorporation of Exhibit A by reference under certain circumstances was not included in the proposed rule. At the suggestion of PASNY, that provision is being retained for major unconstructed projects, and appears in § 4.41.[5]

III. Section-by-Section Analysis

§ *4.30 Who may file.*

Section 4.30 specifies who may file an application for a preliminary permit or a license, paraphrasing, in somewhat streamlined form, the provisions of section 4(e) of the Act, 16 U.S.C. 797(e), that specify who may obtain a license. Paragraph (b) of § 4.30 has been revised to provide additional guidance, specifying that the Commission will not accept an application for a preliminary permit for project works that are already licensed or are authorized for Federal development or that would conflict with a project for which a preliminary permit is outstanding or for which there is an accepted license application. Nor will the Commission entertain an application for a license for project works that are already licensed or are authorized for Federal development or that would conflict with a project for which there is an unexpired preliminary permit, until the permittee submits an application for a license.

§ *4.31 Acceptance for filing or rejection.*

Section 4.31 governs acceptance and rejection of preliminary permit and license applications. Section 4.31(a) provides references to the specific minimum requirements which an application must meet. Besides incorporating certain provisions of the Commission's rules of practice and procedure by reference, the section requires conformance with specific subsequent provisions governing the substance of an application, according to its type.

Section 4.31(b) requires that an original and eleven copies of the application be filed with the Secretary. The treatment of maps and drawings included in license applications is also prescribed.

Section 4.31(c) prescribes the actions which the Commission or its delegate will take upon receipt of a conforming application, including issuance of public notice and, in the event that lands of the United States are affected, notification of the appropriate Federal office under section 24 of the Act, 16 U.S.C. § 818.

Under § 4.31(d), a patently deficient application may be rejected outright.

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[5] Reformed application requirements proposed for major projects at existing dams in Docket No. RM79-36 will obviate this provision except for major unconstructed projects.

Any applicant may be afforded additional time, not to exceed 45 days in the case of a preliminary permit application or 90 days in the case of a license application, to correct application deficiencies. if the deficiencies are not corrected within the time provided, then the application will be rejected. Moreover, § 4.31(e) provides that an application will be deemed "accepted for filing" as of the time of the initial submittal, but only if it is corrected within the time prescribed by the Commission or its delegate. Rejections based on deficiencies would be without prejudice to refiling.

Section 4.31(f) provides that an applicant may be required to provide any additional information or documents which are relevant to an informed decision on the application.

These materials would go beyond the threshold requirements for a conforming application, and their absence from the initial application would therefore not prevent acceptance of the application for filing. Failure to provide the information requested, however, would be sufficient ground for holding the proceeding in abeyance, dismissing the application, or taking other appropriate action. In certain instances, an applicant may also be requested to provide copies of the complete application to specified persons or agencies.

Finally, § 4.31(g) provides that a prospective applicant may submit preliminary copies of its application to the Director, Division of Licensed Projects, for the purpose of obtaining staff advice concerning the sufficiency of the application. Conferences between applicants and the staff regarding deficiencies or other application-related matters are also permitted.

§ 4.32 Specifications for maps and drawings.

Section 4.32 provides the specifications which must be followed in preparing all maps and drawings filed with applications, except as otherwise prescribed. This section supplants the existing § 4.42. All references to § 4.42 elsewhere in the regulations are therefore being amended to refer to § 4.32. A parenthetical explanation of the use of public land surveys is added to the mapping requirements in § 4.32(b)(3). This was done to facilitate more accurate withdrawal of public lands and reservations under section 24 of the Act.

§ 4.33 Disposition of conflicting applications.

Section 4.33 governs conflicting applications for preliminary permits and licenses. Section 4.33(a) permits the filing of a competing application, but requires that the application, or a notice of intent to file such an application, be submitted prior to the end of the period prescribed in the public notice of the initial application for preliminary permit or license for filing of protests and petitions to intervene. Section 4.33(b) prescribes the content of a notice of intent to file a competing application. Under § 4.33(c), if a timely notice of intent is submitted, the prospective applicant will be afforded an additional 60 days beyond the end of the public notice period to submit a competing application for a preliminary permit, or 120 days to submit a competing application for a license.

Section 4.33(d) has been revised to require a competing applicant to provide an analysis of how its plans are equally well (if a municipality or a state) or better adapted to conserve and utilize the water resources of the region in the public interest. Section 4.33(e) provides the initial applicant an opportunity to rebut statements made pursuant to § 4.33(d).

Under § 4.33(f), if an accepted application for a preliminary permit conflicts with an accepted application for a license, and the applicant for a license has demonstrated its ability to carry out its plans, the Commission will favor the applicant for a license. This situation would arise where the Commission has accepted a permit application and, before issuance of permit, a license application is filed and accepted.

Section 4.33(g) sets forth the bases for selection among competing applicants when there are two or more applications for a preliminary permit, or two or more applications for a license by applicants who did not hold an outstanding preliminary permit at the time the license application is filed. These provisions reflect the provisions of section 7(a) of the Act, 16 U.S.C. § 800(a), including the concept of state or municipal preference and the concept that, where the preference does not apply, the applicant whose plan is "best adapted" will prevail. The regulation injects the additional concept that, all other things being equal, the principle "first in time, first in right" will apply. (Whether the state or municipal preference under section 7(a) applies in a relicensing proceeding under section 15(a) of the Act, 16 U.S.C. § 800(a), is the subject of a pending proceeding on a petition for a declaratory order, Docket No. EL78-43.)

Finally, § 4.33(h) provides the bases for selection among competing applicants when there are two or more applications for a license, and one of the applications was filed by a permittee holding an outstanding preliminary permit. The latter applicant is entitled to priority status, all other things being equal, and an opportunity to make its plans as well adapted as any competing applicant's.

§ *4.34 Hearings on applications.*

Section 4.34 provides that the Commission may order a hearing on an application on its own motion or the motion of any party in interest. Hearings are to be limited to the issues prescribed by order of the Commission.

§ *4.80 Applicability and purpose.*

This section states that §§ 4.80 through 4.83 pertain to preliminary permits under Part I of the Act. This section also enunciates the purpose of a preliminary permit, as provided in section 5 of the Act.

§ *4.81 Contents of application.*

Section 4.81 prescribes the information and documents which must be included in an application for a preliminary permit. Section 4.81(a) calls for an initial statement providing the identity and nature of the applicant, the name and location of the proposed project, and the proposed term of the permit.

The remainder of the information is to be provided in four numbered exhibits. Exhibit 1 (§ 4.81(b)) must include a description of the proposed project, including its principal structures and features and any lands of the United States that are affected. While the information need only be provided "to the extent possible," the degree of specificity and completeness of the description could have a bearing on the Commission's assessment of the applicant's ability to complete its studies and license application during the term of the permit, and on a comparison by the Commission of competing applications.

Exhibit 2 (§ 4.81(c)) must consist of a study plan and identification of any related new roads for any proposed project and a detailed work plan and schedule for any project development which would involve new dam construction, meaning that the projects are of such magnitude as to require feasibility studies which include test pits, borings or other geological exploration. The study plan must specify and describe the studies, tests, and plans that have already been carried out or prepared, as well as those projected for completion during the term of the proposed permit. For projects or developments involving new dam construction, a timetable for the projected activities must be submitted. For projects or developments involving new dam construction, Exhibit 2 must also contain information about how environmental disturbances from studies and related activities, including any impact on floodplains or wetlands,[6] will be minimized and the means by which disturbed areas will be restroed. Early consideration of these issues can prevent delay in processing. The study plan and the work plan and schedule will help the Commission monitor the progress of its permittees and hold them accountable, and could also be relevant in assessing competing applications. A new waiver provision pertaining only to the more detailed reporting requirements for developments involving new dam construction is included in Exhibit 2.

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[6] This information on floodplains and wetlands reflects the policy enunciated in the Notice of Proposed Rulemaking in Docket No. RM79-70, issued August 20, 1979, 44 *Fed. Reg.* 49466.

Exhibit 3 (§ 4.81(d)) must contain a statement of costs and financing. An applicant would have to estimate the costs of carrying out or preparing the studies, tests, and plans identified in Exhibit 2, and state the expected sources and extent of financing for those activities. The exhibit also calls for an applicant to provide, to the extent possible, a description of the proposed market for the power generated at the project, including any available information concerning the revenues to be derived from sale of the power.

Exhibit 4 (§ 4.81(e)) must include a map or series of maps showing the location of the proposed project, the physical interrelationships of its principal features, a proposed project boundary, any lands of the United States that would be affected by the project, and any areas in the project vicinity included, or designated for study for inclusion, in the National Wild and Scenic Rivers System or National Wilderness Preservation System. The maps must be based on U.S.G.S. topographic quadrangle sheets or similar topographic maps of a state agency, if available. Section 4.81(e)(3)(ii) is revised to include information on public lands required in clause (iii) of the proposed rule. Mapping of those project lands included in such lands must be accurate to the smallest subdivision of a public land survey, if available, in order to facilitate proper withdrawal of public lands and reservations under section 24 of the Act.

§ *4.82 Amendments.*

Section 4.82 allows permittees to file applications for amendment of their permits. Amendments may include any extension of the term of the permit that does not cause the total term to exceed three years. If an application for an amendment requests a material change in the project, public notice of the application will be given.

§ *4.83 Cancellation and loss of priority.*

Section 4.83 makes clear that a permit may be cancelled for failure of the permittee to comply with the specific terms and conditions of the permit or for "other good cause shown, after notice and opportunity for hearing." Such cancellation, or expiration of the permit before a license application is filed, will result in loss of the permittee's priority of application for a license for the project.

Besides revising, consolidating, and adding to the pertinent existing regulations, this rulemaking would eliminate certain of the regulations altogether. Sections 4.33 and 4.85 governing "issuance and acknowledgment of acceptance" of licenses and preliminary permits, respectively, have been deleted.

Section 4.86, which purported to allow some construction work on a proposed project during the term of the preliminary permit, has also been eliminated. Section 131.10, which prescribes a format for preliminary permit applications, has been deleted as superfluous.

Finally, the incorporation by reference of a certain exhibit has been retained and transferred to § 4.41, pending a rewriting of the licensing procedures for major unconstructed projects.

Effective Date

These amendments to Part 4 of the Commission's regulations become effective November 26, 1979 after publication in the Federal Register.

(Federal Power Act, as amended, 16 U.S.C. §§ 792–828c; Department of Energy Organization Act, 42 U.S.C. § 7101–7352; Executive Order No. 12009, 42 *Fed. Reg.* 46267; Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §§ 2601–2645)

In consideration of the foregoing, the Commission amends Parts 4 and 16 of Subchapter B and Part 131 of Subchapter D, Chapter I, Title 13 of the Code of Federal Regulations, as set forth below.

[¶ 30,092]

44 F. R. 61338 (October 25, 1979)

18 CFR Part 281

[Docket No. RM 79-15; order 29-C]

Natural Gas Curtailment; Order Amending Regulation, Granting in Part and Denying in Part Petitions for Rehearing and Motions for Clarification, Denying Motion for Oral Argument, and Denying Motions To Waive Regulations and Accept Late-Filed Petitions

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rules.

SUMMARY: On May 2, 1979, the Federal Energy Regulatory Commission issued Order No. 29, the permanent curtailment rule in Docket No. RM79-15, implementing section 401 of the Natural Gas Policy Act of 1978. The Commission hereby amends its regulations relating to the permanent curtailment rule, grants in part and denies in part petitions for rehearing and motions for clarification, denies motions for oral argument, and denies motions to waive regulations and accept late-filed petitions, under Order No. 29-A. This order corrects arithmetic errors in the allocation formula of the attribution rule, expands right to protest to the Data Verification Committee to any interested person and extends the scope of the complaint procedure to allow any interested person to file a complaint. It also grandfathers a small customer or small distributor exemption into the curtailment plans and redesignates alternate fuel as alternative fuel and redefines that term to be compatible with the alternate fuel rules in Subpart C.

EFFECTIVE DATE: November 21, 1979

FOR FURTHER INFORMATION CONTACT: MaryJane Reynolds, Federal Energy Regulatory Commission, Office of the General Counsel, 825 North Capitol Street, N.E., Room 8000, Washington, D.C. 20426 (202) 357-8455.

SUPPLEMENTARY INFORMATION:

Final Regulation for the Implementation of section 401 of the Natural Gas Policy Act

Issued October 22, 1979.

On May 2, 1979, the Commission issued Order No. 29, the permanent curtailment rule in Docket No. RM79-15. That order implements section 401 of the Natural Gas Policy Act of 1978 (NGPA).

Timely petitions for rehearing have been filed by Air Products and Chemicals, Inc., Stauffer Chemical Company, and Williamette Industries, Inc., (Air Products), Allied Chemical Corporation (Allied), American Bakers Association (ABA), American Gas Association (AGA), Atlanta Gas Light Company (Atlanta Gas), Brooklyn Union Gas Company (Brooklyn Union), Columbia Gas Transmission Company (Columbia Gas), Columbia Nitrogen Corporation and Nipro, Inc. (Columbia Nitrogen), Consolidated Edision Company of New York (Con Ed), Consolidated Gas Supply Corporation (Consolidated Gas), Eli Lilly and Co. (Eli Lilly), Entex, Inc. and Louisiana Gas Service Company (Entex), Farmland Industries, Inc., and Terra Chemicals International, Inc. (Farmland), The Fertilizer Institute (TFI), Gas Consumers Group (Gas Consumers),[1] General Service Customer Group (GSCG), Natural Gas Pipeline Company of America (Natural), Northern Illinois Gas Company (NI-GAS), Process Gas, Consumers Group and Georgia

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[1] Gas Consumers seeks clarification concerning the effect of Order No. 29 on the small customer exemption provisions of curtailment plans. In the alternative it seeks rehearing of Order No. 29.

Industrial Group (PGC), Southern California Gas Company (SoCal), State of Louisiana, Tennessee Gas Pipeline Company (Tennessee), [2] Texas Eastern Transmission Corporation (TETCO), Transcontinental Gas Pipe Line Corporation (Transco), [3] United Municipal Distributors Group (Municipals), and United States Brewers Association, Inc. (Brewers).

Late petitions for rehearing were filed by United Gas Pipe Line Company (United) and Consolidated Gas Supply Corporation (Consolidated Gas). Consolidated and United filed motions asking the Commission to waive its regulations and accept their late-filed petitions for rehearing. In the alternative, each asks that its petitions be treated as a petition for reconsideration.

Both United and Consolidated Gas aver that their employees left their respective offices on June 21, 1979, in what should have been ample time to file an application for rehearing before the 5:00 p.m. deadline, but they arrived after 5:00 p.m. and the Secretary's office refused to accept the filings.

In effect, petitioners allege nothing to justify their late filings other than that they were late. Under the Commission's Rules of Practice and Procedure, petitioners had a full 30 days within which to file applications for rehearing. That they chose to wait until the last possible minute to file was a decision made at their peril.

Good cause for waiving the regulations pertaining to the filing of applications for rehearing has not been shown. We will, however, treat the petitions filed by United and Consolidated Gas as petitions for reconsideration and will address the merits of the arguments contained therein.[4]

On June 22, 1979, the Commission issued an Order granting rehearing of Order No. 29 solely for purpose of further consideration. We will now discuss the merits of the numerous issues raised by the petitions for rehearing.

Requests for Extension

The filing deadlines established in Order No. 29 were amended by Order Nos. 29-A (44 FR 37499, June 27, 1979) and 29-B (44 FR 45922, August 6, 1979). These subsequent orders render moot requests for reconsideration or extension of the deadlines by Eli Lilly, UGI Corporation, Pacific Gas and Electric Company, So Cal, Texas Eastern, and NI-Gas.

Oral argument

In addition to its petition for reconsideration, State of Louisiana also filed a motion for oral argument on the issue of whether the NGPA has superseded the nondiscrimination requirements of Section 4(b) of the Natural Gas Act, as interpreted in *State of North Carolina* v. *FERC*.[5]

This issue is thoroughly discussed in the comments and petitions of numerous parties to this proceeding. We do not believe that oral argument would add significantly to the record already compiled. State of Louisiana's motion is therefore denied.

Coordination With Rules Implementing Sections 401(b) and 402 of the NGPA

Several parties seek reconsideration on the grounds that the rule implementing section 401(a) is not coordinated with the implementation of sections 401(b) (alternative fuel) and 402 (essential industrial process and feedstock).

GSCG accuses the Commission of creating "moving targets" and argues that the issues of section 401(b) must be addressed before any gas is reclassified in Priority 2. Likewise, Consolidated Gas states that the date for filing data on agricultural uses should be postponed until after rules are issued under section 401(b), because only agricultural users without alternative fuel capability are intended to be protected by the new agricultural priority.

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[2] Tennessee's petition includes a request for clarification.

[3] Transco's petition will not be addressed here, since it was conditionally exempted from the requirements of Order No. 29 by an Order issued on August 2, 1979, in Docket No. RM79-15.

[4] In ruling on these filings the Commission does not waive its right to assert that United and Consolidated Gas are not entitled to seek judicial review of the Commission's order in this proceeding because they failed to apply timely for rehearing of Order 29. See *Boston Gas Co.* v. *FERC*, 575 F.2d 975 (1st Cir. 1978).

[5] 584 F.2d 1003 (1978).

PGC states that the Commission has erred by implementing section 401(b) without regard to the impact on the implementation of section 402.

AGA argues that it will unnecessarily disrupt existing curtailment plans if a rule is issued under section 401(a) before section 401(b) is implemented.

United states that no rule under 401(a) should issue until the "consequences of such action can be considered" together with rules under section 402. United argues that to do otherwise will cause multiple and duplicative collections of data.

It is the Commission's view that its obligations under the NGPA do not permit any further delay in the final implementation of section 401(a). That section is subject to a statutory deadline. Sections 401(b) and 402 are not. Congress clearly intended that implementation of section 401(a) should be given precedence if similarly expeditious implementation of sections 401(b) and 402 was not possible. Given the different data required for implementing those sections and the need to coordinate rulemaking among the Department of Agriculture (USDA), the Economic Regulatory Administration (ERA), and the Commission, the simultaneous implementation of all sections of Title IV would be impossible without substantial delay of a final rule under section 401(a).

In this connection, the Commission observes that section 401 does not preclude reclassifying agricultural uses prior to a determination of alternative fuel availability under section 401(b). On the contrary, the curtailment priorities of section 401(a) must apply unless the Commission determines under section 401(b) that alternative fuel is reasonably available and economically practicable.[6] The absence of a time limit corresponding to the 120 day limit of section 401(a) also supports this interpretation.

Texas Eastern asks that the definition of alternative fuel in section 281.203(a)(16) be changed to include alternative fuel used in facilities other than boilers. Since no rule implementing section 401(b) has yet been implemented, the definition of alternative fuel in Order No. 29 has no present effect.[7] A rule implementing the alternative fuel provision of section 401(b) is under consideration in Docket No. RM79-40. The rule issued in that proceeding will contain a substantive definition of alternative fuel.[8] Nevertheless, to avoid confusion, § 281.203(16) will be amended to define alternate fuel "as it is defined in Subpart C," and to redesignate "alternate fuel" as "alternative fuel."

United and AGA point out that Order No. 29 appears to adopt the final USDA rule, even though only the USDA interim final rule was in effect when Order No. 29 was issued. AGA says that this confusion will make it difficult to comply with the filing requirements of Order No. 29. Both United and AGA urge this as an additional reason for postponement.

In Order No. 29-A, which was issued on June 15, 1979, in this docket,[9] the Commission made it clear that it was adopting the final, not the interim, USDA rule. Order 29-A was issued more than a month before the deadline for agricultural users to file requests for reclassification of essential agricultural uses. There has therefore been ample time for compliance with the requirements of Order No. 29.

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[6] In this regard, section 401(b) differs from section 402(b), which applies the curtailment protection of 402(a) to essential industrial process and feedstock uses "*only if* the Commission determines" that alternative fuel is not. (Emphasis added.)

[7] *See* Notice Concerning June 15, 1979 Filing Deadline. Docket Nos. RM79-15 and RM79-40, June 8, 1979.

[8] *See* Notice of Proposed Rulemaking, Docket No. RM79-40, August 29, 1979.

[9] 44 FR 37499, June 27, 1979.

The Establishment of New Curtailment Priorities

Columbia Gas argues that the NGPA does not require or intend that interstate pipelines reprioritize their existing curtailment plans. Instead, Columbia urges adoption of a final rule based on exemption procedures similar to the interim rule. In support of its arguments Columbia states that (1) requiring pipelines to reprioritize their end-use priorities is inconsistent with Congress' intention to minimize disruption of existing curtailment plans, (2) the Natural Gas Act, as interpreted in *State of Louisiana* v. *FPC*,[10] requires the Commission to tailor any curtailment plan to the particular circumstances existing on that pipeline,[11] and (3) section 5 of the Natural Gas Act, and cases interpreting that section, require the Commission to determine whether an existing curtailment plan is just and reasonable before ordering that plan to be reprioritized.

Columbia's arguments do not support rehearing. In the first place, NGPA does contemplate that interstate pipelines may be required to reprioritize their existing curtailment plans to the extent necessary to comply with Title IV. The Conference Report specifically states:

> For purposes of implementing this section, the Commission is instructed to reopen curtailment plans only to the extent necessary to adjust those plans to bring them into conformity with the new curtailment *priority* schedule.[12]

Furthermore, the ERA rule implementing section 401 provides that the relative order of priorities in existing curtailment plans will remain unchanged only if those priorities do not conflict with the required protection of high priority and essential agricultural uses.[13] Although a rule establishing exemption procedures may be one way of resolving such a conflict, it is not the only way. We understand the ERA rule as providing that, in cases of conflict, the priorities of existing curtailment plans may be changed. This interpretation is consistent with the Conference Report, which assures the Commission that it "has the necessary flexibility in implementing any changes."[14]

The relevance of the Natural Gas Act is discussed in more detail at pages 10–11 *infra*. At this point, it is sufficient to say that the Natural Gas Act and the court cases thereunder do not require rehearing of Order No. 29. For purposes of implementing section 401, the hearing procedures of section 5 of the Natural Gas Act are the kind of "lengthy proceedings which might throw existing curtailment plans into disarray."[15] And if any pipeline does have "particular circumstances" making the rule unsuitable to it, the adjustment procedures of section 502(c) are available.[16]

The interim rule established procedures whereby agricultural users could request adjustments from their suppliers in case of supply deficiencies. This ad hoc approach provides adequate protection during the summer season. When gas supplies were sufficient so that agricultural users did not have to seek relief on a large scale. If curtailments deepen during the winter, however, numerous requests for adjustment could be expected on most pipeline systems. Under such circumstance, the interim rule could be an awkward device, creating much uncertainty in the implementation of curtailments. The Commission believes that the rule of Order No. 29 is more appropriate on a permanent basis. It establishes priorities in advance of curtailment, and allows the pipelines and their customers to plan accordingly.[17]

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[10] 503 F.2d 844 (5th Cir. 1974). The significance of *State of Louisiana* v. *FPC* is discussed at pages 9–10 *infra*.

[11] Columbia Gas mentions no "special circumstances" existing on its system to which the rule should be tailored. Furthermore, Columbia Gas projects no curtailments on its system through 1987.

[12] Emphasis added. H.R. Report No. 95–1752, 95th Cong., 2d Sess. 113 (October 10, 1978) (hereinafter cited as Conference Report).

[13] 10 CFR 580.03(c), 44 FR 15642, March 15, 1979

[14] Conference Report at 113.

[15] *Id.*

[16] *Cf.* Natural Gas Pipeline Company of America and Inland Gas Company, Inc., Docket Nos. TC79–128, et al. (May 2, 1979). The Commission found that the permanent rule was not suited to the curtailment systems of Inland Gas Co., Inc. and Natural Gas Pipe Line Co. Instead, the companies were ordered to file tariffs conforming to the essential character of the rule.

The need to tailor curtailment plans to individual pipelines

United, Columbia Gas, and State of Louisiana criticize the establishment of a single "inflexible" rule applicable to 37 different pipelines.

State of Louisiana argues that the rule is especially inappropriate for United's system, because it would require United to serve the historical base period requirements of its pipeline customers for agricultural and high priority use.[18] According to State of Louisiana, this method of curtailment has never been used on United's system and could result in the curtailment of high priority and essential agricultural uses in United's direct market.

In a related argument, Municipal Distributors also criticize the rule for failing to distinguish between direct and pipeline customers on United's system. Municipal Distributors asks that (1) United be deleted from the list of pipelines included in the rule and (2) United be required to file tariff provisions protecting high priority and essential agricultural customers in United's direct market only.

Citing *State of Louisiana* v. *FPC,*[19] and *Consolidated Edison Co. of New York, Inc.,* v. *FPC,*[20] Columbia Gas asserts that the rule fails to meet the requirement that the Commission tailor any curtailment plan for an individual pipeline to the particular circumstances existing on that pipeline system.

In applying Order No. 29, the Commission has not been inflexible. Where the rule was obviously unsuited to the system of a particular pipeline, it has not been applied.[21] The Commission has also evinced flexibility in molding curtailment plans in the settlement context.[22]

If petitioners believe the rule unsuited to individual pipeline curtailment plans, the appropriate avenue for relief is a 502(c) adjustment or offer of settlement, not rehearing of the rule.[23]

The cases cited by Columbia are inapposite. Besides being decided prior to enactment of the NGPA, those cases applied to the establishment of entire curtailment plans,[24] rather than the limited reopening of established plans to implement a discrete change.

Furthermore, the rule here, unlike the curtailment plans criticized in the cases cited,[25] is related to the record evidence in this particular case.

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[17] This does not mean that the Commission would not approve a plan similar to the interim plan in lieu of an Order 29 plan for a particular pipeline in the context of an adjustment or adjustment/settlement proceeding. In such cases, sufficient focus is placed on the particular situation of the pipeline and on the viability of an interim type plan on a long-term basis. See e.g., *Transcontinental Gas* Pipeline Company, Docket No. RP72-99, *Order Denying Rehearing,* issued August 2, 1979.

[18] State of Louisiana does not describe the rule's effect quite accurately. At least as applied to essential agricultural requirements, the rule would not limit entitlements to base period requirements, but would require that 100 percent of current requirements be served.

[19] 503 F.2d 844, 872 (5th Cir. 1974).

[20] 511 F.2d 372, 381 (D. C. Cir. 1974).

[21] See Note 16 *supra.*

[22] *See* Columbia Gas Transmission Corporation, Docket No. TC79-127, Order Approving Settlement, September 27, 1979.

[23] *See* United Gas Pipeline Company, Dockets Nos. RP71-29, *et al.,* Order Granting Motion to Establish Procedures and Denying Petition for Waiver of Rules, September 28, 1979.

[24] Existing curtailment plans have already been tailored to the needs of individual pipelines in accordance with the above mentioned cases and the requirements of the Natural Gas Act.

[25] In Consolidated Edison Co. of New York v. FPC the court criticized the Commission's rejection of a settlement filed by Transco. The court said that the Commission's belief that curtailment on the bases of the priorities of Order No. 467-B would be better "appears to be premised on the Commission's general policy statement [467-B] rather than an examination of evidence pertaining to the Transco system." 511 F.2d at 381.

Order No. 29 is a rule, not a policy statement, and was based on a record developed in accordance with rulemaking procedures.

The Natural Gas Act

Numerous petitioners challenge the rule on the grounds that it is inconsistent with various provisions of the Natural Gas Act and court decisions thereunder.

PGC asserts that failure of the Commission to determine whether its order meets the standards of the Natural Gas Act constitutes error. Columbia Gas and State of Louisiana both argue that the Commission lacks authority to prevent pipelines from filing, under section 4 of the Natural Gas Act, a plan that does not comply with Order No. 29, but adequately protects high priority and essential agricultural uses. State of Louisiana and United challenge the Commission's authority to establish new priorities for any pipeline without complying with the requirements of Section 5 of the Natural Gas Act.

The NGPA did not repeal the Natural Gas Act (NGA). Nevertheless, it did modify the NGA to require a higher level of protection for essential agricultural uses than for industrial uses.

Order 29 was promulgated to implement the requirements of Section 401. The order satisfies the statutory requirements of Section 401 as well as the requirements of section 4 of the NGA as modified by the NGPA.

Order 29 is a rule and it requires 37 named interstate pipelines to implement Section 401 in a particular and detailed manner. Interstate pipelines may file plans under section 4 of the Natural Gas Act that deviate from Order 29. But such a filing by itself would not waive the requirement to file in accordance with Order 29 *unless* the pipeline has received an adjustment under Section 502(c). A deviant plan filed under section 4 of the NGA cannot go into effect until the requirements of Order 29 have been waived.

Section 401 of the NGPA required an expeditious change in pipeline curtailment plans. The Commission has determined that the only feasible way to meet its obligations in such a short time period was to issue rules requiring all pipelines to amend their curtailment plans. A section 5 proceeding under the Natural Gas Act would be a wholly inappropriate vehicle for implementation of Section 401 in light of the time limits imposed by Congress.[26]

State of North Carolina v. FERC

Many petitioners seek rehearing on the grounds that Order No. 29 fails to meet the requirements of *State of North Carolina* v. *FERC.*[27] For the reason indicated in the preamble to Order No. 29, the Commission does not believe that *North Carolina* controls this rulemaking.[28] Even if that case were applicable, however, Order No. 29 would not be inconsistent with its requirements.

Since the NGPA does not require reopening the base periods of the existing curtailment plans, the issue of stale base period data does not arise under Order No. 29. Moreover, because the Secretary of Agriculture has established essential agricultural requirements on a current basis, such uses will be updated annually and the question of stale data is thereby mooted for these uses.

State of Louisiana, United, Columbia Gas, and Entex all criticize the Commission for failing to assess the rule's "impact on actual end-use." To the extent they argue that the Commission cannot implement section 401 without first collecting voluminous end-use data for each pipeline affected, we reject the argument. Such an effort is not within the bounds of "the maximum extent practicable" and would unduly delay implementation of the rule, perhaps for years. Moreover, to the extent that Order 29 causes a particular hardship, inequity, or undue burden, an adjustment to the rule may be granted.

Contract limitations

Allied, ABA, Columbia Nitrogen, TFI and Brewers argue that contract and certificate limitations should not limit the amount of gas that essential agricultural customers may receive. These parties say that the Commission lacks authority to reduce the amount of gas essential agricultural users may receive below the level of requirements certified by the USDA. Thus, it is argued § 281.204(c)(2) of the Rule must be deleted.

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[26] Because of the delay involved, the Supreme Court has indicated that a section 5 proceeding is unsuitable for evaluating curtailment plans. *FPC* v. *Louisiana P & L*, 406 U.S. 621, 643 (1972).

[27] 584 F.2d 1003 (D.C. Cir. 1978). See petitions for rehearing by Air Products, Atlanta Gas, Columbia Gas, Entex, PGC, State of Louisiana, and United.

[28] Order No. 29 at 5–6.

This same argument was raised by Brewers in its petition for rehearing of the interim rule in Docket No. RM79-13. In the order denying rehearing in that proceeding, the Commission noted that Order No. 29 did not change the volumes certified by the Secretary of Agriculture. The relevant issue was whether or not the pipelines were obliged to meet those requirements regardless of contract or certificate limitations. On this issue the Commission stated that section 401 does not create new contract or certificate obligations. Rehearing on this issue is denied here for the same reasons it was denied in Docket No. RM79-13.[29]

The Commission does not believe that Section 401 creates new contract or certificate obligations for interstate pipelines. Section 401 requires only an amendment to curtailment plans of interstate pipelines. Curtailment plans are a method of allocation of contract demand of natual gas. *FPC* v. *Transcontinental Gas Pipeline Corp.*, 423 U.S. 326, 327-28 (1976).

The attribution formula

Various complaints are raised concerning the attribution rule which apportions high priority and essential agricultural requirements. Entex states that the attribution formula contained in section 281.209 is unworkable and could overstate the agricultural requrements of partial requirements customers. Entex is correct: the rule was intended to attribute exactly 100 percent of essential agricultural requirements by essential agricultural users. The attribution formula as applied by distribution companies and interstate pipelines was intended to allow attribution in the same manner as was done in the underlying curtailment plans of interstate pipelines. Rehearing is granted for the limited purpose of correcting the attribution formula of § 281.209 to reflect Commission intent.

Only interstate pipelines are required to attribute their priority 1 requirements. Distributors are not. Entex says this favors distributors served by more than one supplier. The rule does not require attribution by a distributor because the total base period entitlements of each distributor have already been established by operation of its suppliers' currently effective curtailment plan. The distributor merely determines what volume in its base period entitlements from each supplier reflected end uses now defined under Order 29 as high priority uses. Those volumes are now placed in the new Priority 1 and there is no need for attribution.

Tennessee, on the other hand, argues that it is inconsistent to require even pipelines to attribute high priority requirements, since the rule does not provide for updating high priority requirements and attribution could result in an entitlement different than that currently contained in the base period. To the extent that Priority 1 volumes of interstate pipelines increase (which is purely speculative) it will be caused by the new definition of high priority uses incorporated form the ERA.

NI-Gas and Brewers argue that non pipeline supplies should not be included in the attribution formula. According to NI-Gas, this penalizes distributors that have engaged in self help and may be an unconstitutional taking without just compensation. NI-Gas alleges that by recognizing the status quo of pipeline curtailments, the provision including non pipeline supplies amounts to granting an abandonment without complying with the provisons of the Natural Gas Act.

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[29] Order Denying Rehearing of Interim Curtailment Rule, Docket No. RM79-13, June 20, 1979 at 5-7.

Brewers adds that gas from other sources is likely to be more expensive, and that by including it in the attribution formula, the rule precludes access to lower priced pipeline gas. According to Brewers, this contradicts the purpose of preventing unnecessary increases in the cost of food.

The NGPA does not require that pipelines deliver more gas than is actually necessary to meet the requirements certified by the USDA. On the contrary, the Commission is directed to open existing curtailment plans "only to the extent necessary" to bring them into conformity with the new priority schedule.[30] Therefore, to the extent that essential agricultural requirements are being met by non-pipeline sources, they will not be reclassified in the pipeline's curtailment plan. Otherwise, the rule would extend Priority 2 protection to agricultural users, whose needs are being met from other sources at the expense of lower priority users, including industrial process and feedstock users.

The inclusion of non-pipeline sources in the attribution formula deprives no one of gas. It only prevents users from receiving additional gas to serve requirements being met from another source.

The Base Period

AGA, GSCG, Natural, United, PGC, Brooklyn Union, and ConEd all challenge the use of an updated or rolling base period for calculating agricultural requirements. These petitioners maintain that it is improper to extend Priority 2 protection to new or expanded agricultural uses not included in existing curtailment plans.

In a related argument, PGC, Natural, United, Brooklyn Union, and GSCG say that it was error for the Commission to adopt completely the USDA certification of 100 percent of current agricultural requirements.

These arguments were raised in petitions for rehearing in Docket No. RM79-13 and were rejected. They are rejected here for the same reasons.[31] Furthermore, when Order No. 29 was promulgated, the Commission fully explained the basis for its decision to expand the requirements above base period volumes.[32]

PGC argues that because the USDA certification is incorporated into the ERA rule, the Commission has authority under sections 403 and 404 of the DOE Act to review that certification. USDA's authority to certify agricultural requirements is independent of any authority the NGPA grants to ERA or the Commission. This authority therefore cannot be diluted or made subject to our review simply because it is recognized by the ERA rule.

Brooklyn Union further challenges adoption of agricultural entitlements equal to 100 percent of current requirements because there has been no showing that expanded service is "necessary" for "full food and fiber production" or that adherence to existing base periods would impair operations of essential agricultural users.

No such showing is required, or even relevant, in this proceeding. Determinations of what is necessary for full food and fiber production are the province of the USDA, not the Commission. Likewise, whether or not adherence to existing base periods would impair essential agricultural uses is not the issue. The issue is whether or not adherence to existing base periods would fulfill the Commission's duty to implement the USDA certification of 100 percent of current requirements. For reasons already mentioned we find that it would not.

Capacity Limitations

Farmland and TFI seek rehearing on the grounds that the protection afforded by section 401 and Order 29 should apply to curtailments resulting from capacity limitations as well as from supply shortages. Farmland urges that § 281.203(a)(6) (definition of end-use curtailment) be modified accordingly.

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[30] Conference Report at 113.

[31] Order Denying Rehearing of Interim Curtailment Rule, Docket No. RM79-13, June 20, 1979, at 6-11.

[32] Order No. 29 at 12-13 (44 FR 26855, 26857).

The NGPA does not define the term "curtailment plan." In large part, curtailment has been a method of dealing with natural gas shortages vis-a-vis contract obligation to deliver natural gas. For example, Order 467–B established end-use priorities for deliveries of natural gas in the face of a supply shortage. If TFI and Farmland face supply problems in the absence of curtailment, they may avail themselves of their Natural Gas Act remedies. Accordingly, rehearing on this issue is denied.

Burner Tip Curtailment

Allied, ABA, Columbia Nitrogen, and TFI assert that Order No. 29 is in error because is does not require local distributors to deliver gas to the end-users to whom agricultural uses are attributable.

The Commission's authority to establish curtailment plans for interstate pipelines is founded in its transportation jurisdiction under section 1(b) of the Natural Gas Act.[33] Section 1(b) of that act, however, specifically prohibits the exercise of Commission jurisdiction over "the local distribution of natural gas." Consequently, it has not been Commission policy to attach end-use conditions to pipeline curtailment plans.[34]

Nothing in section 401 indicates an intention to expand the Commission's jurisdiction to include local distributors. On the contrary, the House bill would have applied the curtailment prohibitions of section 401 to local distribution companies, but this provision was deleted from the final act.[35]

There are sound policy reasons that weigh against extending the Commission's curtailment jurisdiction to include local distributors. Such an extension of curtailment jurisdiction would create inevitable conflict with local regulatory agencies. Moreover, it would not be feasible for this agency to administer workable curtailment plans for the thousands of local distributors throughout the country. State agencies, on the other hand, are in a position to know the practices and requirements of local distributors and their customers.

In addition, if conditions requiring the flow through of gas were imposed, the Commission would face the dilemma of applying those conditions only for high priority and essential agricultural uses, or reopening every curtailment plan to provide flow-through to all priorities.

For these reasons, rehearing in this issue is denied.

GSCG asks that the rule be amended to indicate that it does not require "State commissions to order local distribution companies to add new customers, increase deliveries or execute new or modified contracts or service agreements." The rule is so clarified. A specific amendment is unnecessary.

"Necessary adjustments" to current requirements.

ABA, TFI, Farmland and PGC all question the meaning of the rule's definition of current requirements (Section 281.208(b)(1)(ii). Farmland argues that it is improper to impose an historical base period restriction on agricultural requirements. ABA and TFI urge that the phrase "with necessary adjustments" be interpreted to permit calculation of actual protected current requirements rather than limit agricultural users to the amount of gas used in a prior time period.

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[33] *FPC v. Louisiana Power & Light Co.,* 406 U.S. 621, 636–41 (1972).

[34] Opinion No. 754, Panhandle Eastern Pipe Line Co., Docket No. RP71–119, February 27, 1976, at 31–33.

[35] Allied argues that because the Senate passed legislation was designed to deregulate natural gas within the framework of the Natural Gas Act, it cannot be concluded that the Senate intended to reject the Houses's inclusion of local distribution companies. This argument is not persuasive, especially if the intention was to deregulate within the frame work of the Natural Gas Act. As has been shown, the Natural Gas Act specifically excludes local distribution from Commission jurisdiction.

PGC, on the other hand, says that it is error to include "energy consumption" within the definition rather than "natural gas consumption."

The definition of current requirements is intended to implement fully the USDA certification of 100 percent of current requirements. This certification would not be fully recognized if essential agricultural users who used alternative fuel as a result of past curtailment are limited to whatever amount of gas they were able to obtain or use during that period. Consequently, current requirements are defined to include total energy requirements rather than natural gas only.

The phrase "with necessary adjustments" is intended to provide for users who have significantly expanded their capacity since the most recent 12 month period for which data is available or who may have been operating at less than full capacity during that period and are now at full capacity. The rule uses the most recent 12 month period for which data is available as the most practicable method for making an objective determination of current requirements. If this period would not accurately reflect the current requirements of particular agricultural users because of significant changes in capacity, however, these changes may be reflected in a "necessary adjustment" to the collected data.

The rule does not limit agricultural users to an historical base period. Essential agricultural users may submit requests to change their Priority 2 entitlements under § 281.211(b)(4).

Storage Gas

Order 29 retains the status quo of storage gas. For those pipelines which sprinkle, storage volumes will be spread over all priorities, including the new high-priority and essential agricultural uses. For those pipelines which treat storage as an end use and place the volumes in old Priority 2 the curtailment plan under Order 29 will result in putting these volumes in a lower priority.

Nobody protests the results of those pipelines which sprinkle storage volumes. AGA, Brooklyn Union, Columbia Gas, GSCG, Natural, Consolidated Gas and NI-Gas object to the downgrading of storage gas for those pipelines which have previously placed storage in Priority 2.

By maintaining the status quo, the Commission believes it can best implement the Congressional intent of avoiding protracted litigation and extensive reopening of curtailment plans. Nonetheless, if the status quo for any of those few pipelines which do not use storage sprinkling will lead to "an undue preference or advantage" or the maintenance of "unreasonable difference in . . . Service . . . either as between localities or between classes of services, the pipelines may make an appropriate filing to modify its treatment of storage volumes.

Certain petitioners assert that Order 29 violates the ERA rule:

> "Nothing in this rule shall prohibit the injection of natural gas into storage by interstate pipelines or deliveries to its customers for their injection into storage unless it is demonstrated to the Federal Energy Regulatory Commission that these injections or deliveries are not reasonably necessary to meet the requirements of high-priority or essential agricultural users. 10 CFR 580.03(d)

Stripped of its negatives, the rule is intended to allow the Commission flexibility in treatment of storage volumes.[36] And in the absence of a showing that storage is used exclusively to serve high-priority and essential agricultural requirements or that failure to fill storage may result in insufficient supplies to serve those requirements in the winter, we will not adopt the suggestions that storage injection be included as a high-priority use.

Small Distributors Exemptions

Gas Consumers asks clarification to indicate that the rule was not intended to effect the exemption of small distributors from curtailment, as provided in many pipeline curtailment plans. Gas Consumers advances many policy and factual arguments in support of retaining the small distributor exemptions.

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[36] See 44 FR 15642, 15645, March 15, 1979.

We agree with the arguments advanced by Gas Consumers. The Commission has previously found the small distributor exemptions to be in the public interest. Order No. 29 was not intended to disturb these exemptions. The rule is so clarified.

Payback Obligations

Section 281.214(b) of the rule provides for payback in dollars or in kind as a remedy for violations of the rule. GSCG urges that payback be prescribed for any gas that is misclassified. According to GSCG, this deterrent is necessary to assure that only the minimum amounts of gas are upgraded, especially since alternative fuel determinations have not yet been implemented.

GSCG states that in its Notice of Proposed Rulemaking the Commission indicated that it would require payback if gas is misclassified by the data verification committee. This is inaccurate. The notice said that "the Commission will grant relief prospectively" when high priority and essential agricultural uses are misclassified and that "the Commission reserves the right to order payback of excess volumes in appropriate cases." Section 281.208(c)(4) of the proposed rule provided that "[t]he Commission *in its discretion may* direct the payback to excess volumes taken while the end-user was temporarily misclassified." (Emphasis added.)

The final rule is consistent with, albeit not identical to, the provisions of the notice and the proposed rule. We would not extend the rule to require payback in cases of simple error. It would not be consistent with the purpose of protecting high priority and essential agricultural uses to put this risk on those who make good faith requests for classification under Order No. 29.

Requests for classification of essential agricultural requirements are required to be under oath (section 281.211(b)(iii)). We believe that this requirement, along with the remedies established in 281.214(b), provides sufficient deterrent to misclassification.

Schools and Hospitals

GSCG asks that the rule be amended to clarify the definitions of schools and hospitals. GSCG says that it is unclear whether "dormitories, administration buildings, and laboratories" would come within the definition of school. To the extent such buildings are an integral part of "a facility, the primary function of which is to deliver instruction to regularly enrolled students in attendance at such facility," they would come within the definition.

GSCG asks that the sentence excluding "outpatient clinics or doctors offices" from the definition of hospital be stricken, since such buildings are part of the hospital complex in some instances.

It would not be administratively feasible to distinguish for separate curtailment treatment outpatient clinics and doctors offices that are physically connected to the rest of the hospital or its heating plant. Such uses should be considered part of the "facility" and included within the definition. Otherwise they are excluded.

Clarification of these issues obviates the need for further amendment.

Consultations With USDA

PGC suggests that the Commission's consultations with USDA may have violated *ex parte* regulations because section 401(b) only authorizes consultations concerning alternative fuel determinations. We do not give section 401 such a limited reading. As numerous petitioners for rehearing, including PGC,[37] remind us, our responsibilities under sections 401(a) and 401(b) are closely related. In any event, memoranda submitted to the Commission by the USDA pursuant to its consultations are in the public record of this proceeding.[38]

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[37] See PGC petition at 9.

The Data Verification Committees (DVCs)

PGC urges that a representative of an industrial process or feedstock user should be included on all DVCs. Section 281.213 was never intended to preclude representation on the DVCs by representatives of other industries.

Protests and Complaints

PGC criticizes § 281.213(c), which limits protests to customers of the interstate pipeline. Section 281.214(a), limiting complaints to aggrieved direct customers and distribution companies, is similarly criticized. PGC would extend standing under these sections to "all interested parties." We agree. This policy is appropriate in light of the new policy of end product curtailment embodied in the NGPA. Order 29 will be modified to allow full participation by all interested persons.

Filing Requirements

Section 281.204(a) requires pipelines subject to the rule to file tariff sheets "including an index of entitlements." Tennessee submits that because its index of entitlements is so voluminous, this requirement is unnecessary and unduly burdensome. Tennessee notes that its present index of entitlements totals 132 pages and that base period data used by most pipelines has not been included in company tariffs in the past.

As an alternative, Tennessee suggests that it file its complete index of entitlements with the Commission and serve copies on its customers and affected state commissions.

Tennessee was the only party to raise this issue. If Tennessee should find the filing of an index of requirements unduly burdensome, it may seek an adjustment.

Rate Adjustments

Tennessee states that any significant change in its base period data in conformance with Order No. 29 could affect the sales volume estimates underlying its rates and cause a loss of necessary revenues. Tennessee concern appears to be speculative and beyond the scope of Order 29.

The Commission orders: For the reasons set forth above, the Commission orders:

A. The petitions for rehearing and clarification are granted to the extent indicated in the body of this order. Otherwise they are denied.

B. The motions by United and Consolidated Gas for acceptance of late filed petitions for rehearing and waiver of the Commission's Rules of Practice and Procedure are denied.

C. Petitions for extension of filing deadlines by Eli Lilly, Pacific Gas, UGI Corporation, So Cal, Texas Eastern, and NI-Gas are dismissed as moot.

D. The motion for oral argument filed by State of Louisiana is denied.

E. Subpart B, Part 281, Subchapter I, Chapter I of Title 18, Code of Federal Regulations, is amended as set forth below, effective November 21, 1979.

(Natural Gas Act, 15 U.S.C. 717–717w; Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432; Department of Energy Organization Act, 42 U.S.C. 7101–7352; E.O. 12009, 42 FR 46267.)

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,093]

44 F. R. 61946 (October 29, 1979)

18 CFR Parts 2, 3, 4, 141, and 260

[Docket No. RM79-38; Order No. 53]

Discontinuation of the Use of Certain FERC Forms; Final Rule

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final Rule.

SUMMARY: Notice is hereby given that the Federal Energy Regulatory

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[38] Notice of Proposed Rulemaking, Docket No. RM79-15, January 18, 1978, at 8 n. 2.

Commission (Commission) is amending its regulations to discontinue the use of fifteen data collection forms no longer needed by the Commission to carry out its regulatory responsibilities.

DATES: Effective October 19, 1979: Forms Nos. 6, 7, 9, 17, 23B, 38, 45, 64, 237A, 237B, and ICC–ARC–41 are discontinued, and the amendments to the Commission's regulations which relate to these forms become effective.

Effective January 1, 1980: Forms Nos. 1M, 13, Unnumbered (RO309), and Unnumbered (RO327) are discontinued, and the amendments to the Commission's regulations which relate to these forms become effective.

FOR FURTHER INFORMATION CONTACT: Barbara K. Christin, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Room 8113, Washington, D.C. 20426. (202) 357–8079.

October 23, 1979.

I. Background

On April 19, 1979, the Federal Energy Regulatory Commission (Commission) issued a Notice of Proposed Rulemaking (44 FR 24577, April 26, 1979) to discontinue the use of fifteen data collection forms no longer needed by the Commission to carry out its regulatory responsibilities. Having reviewed the comments received on the April 19th Notice, the Commission hereby amends its regulations to discontinue the fifteen forms described in that Notice.

In the Notice of Proposed Rulemaking, the Commission stated that, although the Commission was proposing to discontinue the collection of the data in these forms, the Energy Information Administration (EIA) or the Economic Regulatory Administration (ERA) of the Department of Energy (DOE) might wish to continue to collect some of the data elements in order to discharge their respective statutory or delegated responsibilities. In order to assure sufficient time for EIA or ERA to justify the need for and receive OMB approval of the collection of such data, this final rule provides for a delayed effective date for the discontinuation of those forms which EIA or ERA has expressed an interest in collecting.

II. Forms To Be Discontinued

Twenty-five coments were received in this docket. Based upon a review of these comments and its own analysis, the Commission will discontinue collection of the fifteen forms described below.

A. *Forms that serve no regulatory purpose.* The twenty-five comments received in this docket supported the Commission's proposal with respect to discontinuing the following nine forms:

Form No	Title as shown in CFR	18 CFR §§
6	Initial Cost Statement for Licensed Projects.	3.142(a)(23) and 141.11
7	Statement of Actual Legitimate, Original Cost of Construction.	3.142(a)(24) and 141.12
9	Annual Report for Licensees of Privately Owned Major Projects (Utility and Industrial).	3.142(a)(25) and 141.13
23B	Quarterly Electric Utility Generation and Fuel Planning Report (Expired 8-31-78).	3.142(a)(42) and 141.300
38	No CFR title. Title of form: Electric Generating Station and Substation Data and Location.	(None—internal use only)
45	Report of New Non-Jurisdictional Sales of Natural Gas.	3.170(a)(30) and 260.20
64	Natural Gas Companies, Annual Report of Producer Expenditures, Exploration and Development Activity, Production, Reserve Additions, and Revenues (Expired 12-31-78).	3.170(a)(27) and 260.21
237A	Weekly Fuel Emergency Report, Revised (Coal).	3.142(a)(45) and 141.60
ICC ARC–41	No CFR title. Title of form: Report of Expenditures for Additions and Betterments—Oil Pipeline Companies.	(None—internal use only)

Several commenters objected to the discontinuation of the following two forms for reasons unrelated to the Commission's regulatory need for the data.

Form No	Title as shown in CFR	18 CFR §§
17	Monthly Report of Natural Gas Pipeline Curtailments.	None
237B	Weekly Fuel Emergency Report, Revised (Oil).	3.142(a)(45) and 141.60

The reasons given for continued collection of these two forms focused on the public's interest in the information. The Commission recognizes that the public might have some interest in the information collected by way of these two forms, but does not believe that this reason by itself justifies continued collection of the information by the Commission. As stated above, the data collected in these forms is not needed by the Commission to perform its regulatory responsibilities.

Since the effect of this final rule is to eliminate a requirement imposed on industries regulated by the Commission, the Commission finds good cause to waive the 30 day requirement set forth in 5 U.S.C. 553(d) and to make this final rule effective immediately. Thus, the eleven forms described above are discontinued as of the date of issuance of this rule.

B. *Forms identified for collection by EIA and ERA.* Several comments expressed a need for some of the information contained in the following four forms and requested that, if the Commission should discontinue these forms, EIA or ERA assume sponsorship of the forms and continue to collect the information.

Form No.	Title as shown in CFR	18 CFR §§
1M	Annual Report for Municipal Electric Utilities Having Annual Electric Operating Revenues of $250,000 or More.	3.142(a)(22) and 141.7
13	Summary for National Electric Rate Book.	3.142(a)(32), 141.26
Unnumbered (GAO authorization No. RO309).	Untitled. Information reported: Reliability and adequacy of electric services—report by regional councils on coordinated regional bulk power supply programs.	2.11 (c), (d)
Unnumbered (GAO authorization No. RO327).	Untitled. Information reported: Actions for minimizing the consequences of bulk power supply interruptions or shortages—report on contingency plans for operating in emergency situations and for possible load reductions or curtailment.	2.10(b)

EIA has indicated to the Commission that it plans to continue to collect from municipalities the information analagous to that requested by Form 1M. In addition, EIA will continue to collect, on behalf of ERA, the data contained in Forms 13, Unnumbered (RO309), and Unnumbered (RO3270.

To allow EIA time to receive OMB approval for collection of the information, the Commission will comply with EIA's request to continue these forms until the end of calendar year 1979. Accordingly, the effective date for discontinuing the above four forms is January 1, 1980.

III. Other Amendments

In the April 19th Notice, the Commission proposed to amend Part 4 of its regulations to eliminate the requirements for filing Forms 6, 7, and 9 with the Commission. As discussed in the April 19th proposal, under Part 4 of the regulations the actual legitimate original cost of and the net investment in a project is determined by the Commission after an audit is conducted by Commission staff. Forms 6, 7, and 9 are unnecessary because the information reported therein is later obtained by Commission audit.

Under the regulations proposed in April, prior to an audit, a licensee of a licensed project would have to file a letter instead of Forms 6, 7, and 9. The letter would have to state that all the information needed for the Commission's determination was contained in the project's books of accounts and was recorded in compliance with the Commission's Uniform System of Accounts. The final regulations incorporate the letter procedure proposed in April.

Two comments suggested minor alterations in the wording of the proposed regulations. One of these comments suggested a simplification in the wording of the proposed § 4.20. The Commission has incorporated this change in the final regulations.

The other comment expressed concern that the proposed §§ 4.1, 4.10, and 4.20 would require a project to bear the cost of duplication of any records which must be made available to the public under those provisions. The Commission agrees that the person who requests the information should bear the costs of duplication, and the final regulations reflect this change.

The Commission emphasizes that the Part 4 regulations, as amended by this final rule, place no additional burden on projects subject to the regulations. The final regulations do not require projects to keep their books in any greater detail than is presently required under the Uniform System of Accounts.

IV. Effective Date

For the reasons stated above, Forms Nos. 6, 7, 9, 17, 23B, 38, 45, 64, 237A, 237P, and ICC-ARC-41, are discontinued immediately. The amendments to the Commission's regulations which relate to these forms are also made effective immediately.

In addition, for the reasons stated above, Forms Nos. 1M, 13, Unnumbered (R0309), and Unnumbered (R0327), will be discontinued as of January 1, 1980. The amendments to the Commission's regulations related to these forms will become effective January 1, 1980.

(Department of Energy Organization Act, (42 U.S.C. 7101, *et seq.*); E.O. 12009, 42 FR 46267.)

In consideration of the foregoing, Title 18 of the Code of Federal Regulations is amended in Parts 2, 3, 4, 141, and 260 of Chapter I, as set forth below, effective October 19, 1979, except as otherwise indicated.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,094]

44 F. R. 61950 (October 29, 1979)

18 CFR Parts 272 and 274

[Docket No. RM79-44]

Interim Rules Defining and Deregulating Certain High-Cost Natural Gas

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Interim rules.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts interim regulations defining and deregulating high-cost gas described in section 107(c) (1), (2), (3) and (4) of the Natural Gas Policy Act of 1978, and prescribing the filing requirements for such gas. Further comments are solicited on the rule.

EFFECTIVE DATE: November 1, 1979.

COMMENT DATE: Additional comments are due November 26, 1979.

ADDRESS: All comments should reference Docket No. RM79-44 and be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Mr. Victor Zabel, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 275-4568. Mr. Phillip Yates, Office of the general Counsel, Federal Energy Regulatory Commission, 825

North Capitol Street NE., Washington, D.C. 20426, (202) 357-8078.

October 24, 1979.

I. Background

On June 13, 1979, the Federal Energy Regulatory Commission (Commission) issued a notice of proposed rulemaking in Docket No. RM79-44 (44 FR 34969, June 18, 1979). In that notice, the Commission promulgated proposed definitions for certain categories of high-cost natural gas as defined in section 107 of the Natural Gas Policy Act of 1978 (15 U.S.C. 3301 *et seq.*) (NGPA). Specifically, the Commission proposed definitions for natural gas produced from geopressured brine (section 107(c)(2)), occluded natural gas produced from coal seams (section 107(c)(3)), and natural gas produced from Devonian shale (section 107(c)(4)). Further, the Commission indicated that it would prescribe filing requirements for these categories of natural gas similar to those established for other categories in Subpart B of Part 274 of our regulations.

Twenty-seven written comments were received in response to the notice, and two parties addressed the definitions in the public hearing held on September 25, 1979 in this docket. Each proposed definition has been changed in response to the comments received.

II. Analysis of Comments and Discussion of Amendments

(A) Section 107(c)(2)—Natural gas Produced From Geopressured Brine.

Five commenters addressed the proposed definition for natural gas produced from geopressured brine. The proposal read as follows:

> "Natural gas produced from geopressured brine" means: natural gas dissolved in subsurface (sic) brine aquifers with reservoir geopressures substantially in excess or normal saltwater hydrostatic pressures, such geopressures being due, in part, to the formation waters bearing a portion of the weight of the sedimentary over (sic) overburden.

Three commenters objected to the use of the phrase "substantially in excess of normal saltwater hydrostatic pressures." The Commission agrees that the phrase should be replaced with a quantifiable standard. As noted in the proposal, the word "geopressured" connotes pressures in excess of normal hydrostatic pressures. Since 0.465 pounds per square inch (psi) per vertical foot is the normal salt water hydrostatic pressure gradient, the Commission has determined pressures in excess of that pressure to be "geopressured".[1] The Commission also agrees with a commenter's suggestion that *initial* reservoir pressures should be used in measuring the hydrostatic pressure gradient because reservoir pressures may change after production begins. Commenters also suggested that we should delete the phrase prescribing the cause for the higher geopressures since the cause of geopressures is not relevant to the statutory definition. We agree; nothing in the statute indicates that the cause of the pressure is relevant to qualification under this category of gas. Therefore, any reservoir with an initial pressure gradient in excess of 0.465 psi per vertical foot will qualify as geopressured, regardless of the cause of the geopressure.

The Commission cannot agree with a suggestion that natural gas production from a "natural gas cap" (i.e., gas which is freed from solution, forming a cap at the top of the reservoir) should qualify as production from geopressured brine. The statute requires that the gas be produced *from* the brine. Gas not dissolved in brine, such as gas caps, may be economically produced through less expensive conventional production techniques and is not a high-cost gas. Therefore, if the gas has broken free from the brine before initial production

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[1] National Gas Survey, Sub-Task Force I—Gas Dissolved in Water, DOE/FERC 0029, March 1979, page 13.

(before any fluids are withdrawn from the reservoir), it will not qualify under this definition.

Some commenters also suggested that the definition of "geopressured brine" should be expanded to include gas produced from waters that are not "brine". The Commission has no authority to abrogate a statutory requirement. However, the nature of the comment did point out the need to adopt some standard for determining when water is "brine". The commission considers "brine" to be water which contains at least 10,000 parts of Sodium Chloride per million parts of water and has incorporated this standard in the definition.[2]

(B) Section 107(c)(3)—Occluded Natural Gas Produced From Coal Seams

Ten commenters addressed the definition of occluded natural gas produced from coal seams, which read as follows:

> "Occluded natural gas produced from coal seams" means: natural gas released during a mechanical degradation process from entrapment between the seams and in the micropores of beds of coal.

Several of the written comments objected to the requirement that the gas be released during a "mechanical degradation process" on the grounds that the requirement is too restrictive. We agree that the phrase "mechanical degradation process" may be interpreted to preclude processes such as drilling or fracturing and therefore should be deleted. The definition promulgated herein allows gas produced by processes such as drilling or fracturing to qualify as occluded natural gas. However, we do not intend to include in the definition methane produced by the underground gasification of coal. Such gas is not "natural," and the phrase "naturally occurring natural gas," in the interim rule, is intended to preclude such gas from qualifying.[3]

Further, the Commission cannot exclude from the definition, as one commenter suggested, occluded natural gas from coal seams which may not be particularly expensive to produce. The statute establishes a category for occluded natural gas from coal seams without reference to the actual cost of production. The Commission must follow the statutory guideline.

Several commenters suggested that the definition inadvertently included natural gas which is found in strata *between* seams of coal. In order to avoid such a result, the final rule has been amended to include only gas which is produced from the coal seam.

(C) Section 107(c)(4)—Natural gas Produced From Devonian Shale

The proposed definition of natural gas produced from Devonian shale read as follows:

> Natural gas "produced from Devonian shale" means: natural gas produced from the fractures, micropores and bedding planes of shales deposited during the Paleozoic Devonian Period as generally found in the subsurface of the Appalachian Basin and in surface outcrops aroung (sic) its periphery. For the purpose of this definition, Devonian shale is defined as that shale stratigraphic interval that lies between the base on the Missjssippian Berea Sand or, if absent, the base of the Osage Series, and the top of the Onondaga limestone formation or its chert equivalent, the top of the Hunton group of carbonates.

Nine parties commented on the proposed definition. Most suggested that it was too limited, because it excluded those Devonian shales not found in the Appalachian basin. The Commission agrees that there is no basis upon which to exclude such Devonian shales from the definition. Consequently, the Commission has expanded the definition to include natural gas produced from *any* shale deposited during the Paleozoic Devonian Period.

Other commenters suggested that the definition should be expanded to include natural gas that is produced from shales other than "Devonian" or from lithologies, other than shales, that were laid down during the Paleozoic Devonian Period. The Commission does not have the authority to expand the definition as these commenters suggest and therefore does not adopt the suggestion.

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[2] See Figure 11, page 43, Potential Supply of Natural Gas in the United States, Potential Gas Committee.

[3] Two comments requested that the Commission include in the definition a reference to the source of the gas. We do not feel that origin of the gas is significant, so long as the gas occurs naturally.

The Commission is cognizant of the fact that both coal and Devonian shale lithologies may contain "stringers" of potentially gas producing rock between the seams of coal or Devonian shale. If natural gas is produced from one of these stringers it would not qualify under these definitions. Production from these stringers would not be deregulated, and would have to be priced at the maximum lawful price applicable to the well. If such gas and deregulated gas were produced from a single well, pricing for gas from such a partially deregulated well would be based on a reasonable allocation of production from the different producing intervals. The Commission invites comments on how such allocation should be determined.

III. Requirements for Filing With Jurisdictional Agencies

As indicated in the notice issued June 13, 1979, we are promulgating for gas subject to section 107(c)(2) jurisdictional agency filing requirements which are similar to those imposed for other categories of gas. In order for natural gas to qualify as high-cost natural gas under section 107(c)(2), (3) or (4), the gas must be qualified in accordance with the procedures mandated by section 503 of the NGPA. Under Part 274 of our regulations, producers must submit certain information to the appropriate jurisdictional agency. See 18 CFR 270.102(b)(12). After review of this information, the jurisdictional agency determines whether the gas qualifies under the section of the NGPA for which the producer has filed. The jurisdictional agency then submits a notice of the determination to the Commission. If the Commission does not reverse or remand the jurisdictional agency determination within 45 days, that determination becomes "binding with respect to such natural gas." See NGPA section 503(d)(1), and Part 275 of our regulations.

In order to verify the specific geological parameters of the definitions, new filing requirements must be imposed. The gamma ray log was suggested in the comments for identifying gas produced from coal seams and Devonian shales. This test will enable the jurisdictional agency and the Commission to differentiate between those strata that qualify under these definitions and those that do not.

For natural gas produced from geopressured brine, the producer must submit an FERC Form 121, a well completion report, a bottom-hole pressure test report, or other information to establish that the initial reservoir geopressure gradient is in excess of 0.465 pounds per square inch per vertical foot, and evidence[4] to establish that the gas from the well was in solution in a brine before production.

For occluded natural gas produced from coal seams, the producer must submit an FERC Form 121, a gamma ray log, a well completion report, and evidence to establish that the producing interval is a coal seam.

For natural gas produced from Devonian shale, the producer must submit an FERC Form 121, a gamma ray log, a well completion report, and a reference to a standard stratigraphic chart or text establishing that the producing interval is a Devonian shale.

IV. Deregulation Under the Interim Rule

Pursuant to section 121(b) of the NGPA, the first sale price of high-cost natural gas as described in section 107(c) (1), (2), (3) and (4) become deregulated on the effective date of the incremental pricing rule required under section 201 of the NGPA. That rule, issued in Docket No. RM79-14 on September 28, 1979, becomes effective on November 1, 1979; therefore, Part 272 and the amendments to Part 274 becomes effective on November 1, 1979. The proposal issued in this docket did not discuss issues concerning the effective date of deregulation for each qualifying well, interim collection of the deregulated rate pending final determination, and the proper method of treating pipeline passthrough of the costs of its own production of deregulated gas. These issues must be resolved in any final rule; therefore, the Commission issues this rule as an interim rather than a final rule and invites further comments on these issues.

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[4] This evidence could be results of a laboratory test of a bottom-hole sample.

Under the interim rule, the price which may be charged for gas which a jurisdictional agency determines to be high-cost gas defined in this rule becomes deregulated when the jurisdictional agency eligibility determination concerning that gas becomes final; i.e., when the determination is no longer subject to Commission action. See 18 CFR 273.102. Under the interim rule, the Commission will not allow collection of the deregulated rate so long as the final determination is pending. Between the time the application for determination is made, and the time the determination becomes final the gas will continue to be subject to any otherwise applicable maximum lawful price. Once the determination becomes final, the parties to the sale may make retroactive price adjustments for deliveries which took place between the later of November 1, 1979, or the time the application was filed and the time the determination became final. However, such adjustment may be made only if specifically authorized by the contract. Such adjustments may not exceed the aggregate amount by which the deregulated contract price exceeds the price collected between the date the application was filed (or November 1, 1979, if later) and the date the determination became final; plus interest on such aggregate amount (determined at the rate prescribed in § 154.102(d)(2)).

Additionally, § 272.102(c) of the interim rule provides that no portion of the price paid for deregulated gas may represent consideration for gas regulated under Part 271. Section 272.102(c) is designed to preclude circumvention of the Commission's ceiling price regulations under Part 271 of its NGPA regulations, by requiring "unbundling" of gas sales transactions so that regulated and unregulated transactions are separately priced.

Although it has not done so in the interim rule, the Commission is considering allowing interim collection of the lesser of the contract price or the section 102 maximum lawful price under the final rule. Once the determination becomes final, the parties to the contract would be able to make retroactive collections of the amount (if any) by which the contract price exceeds the section 102 maximum lawful price. The Commission is specifically soliciting comments on this proposal.

The Commission also requests comments on the proper way to treat the pass-through in purchased gas adjustment clauses of the first sale acquisition costs of an interstate pipeline affiliate's production of gas deregulated under Part 272. The Commission is also soliciting comments on whether pipeline or affiliate production qualifying under section 107(c)(1) through (4) should receive the deregulated price or be subject to a ceiling price if it is not accorded first sale treatment but is priced by reference to the NGPA under § 2.66a.[5] If it should be subject to a ceiling price, what price should that be?

Finally, the Commission requests comments on all other portions of the interim rule and on all other aspects of the implementation of Subtitle B of Title I of the NGPA.

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[5] Considered at the Commission's meeting of October 10, 1979 to be issued as a Notice of Proposed Rulemaking (Undocketed).

V. Comment Procedures, Public Hearings and Effective Date

Because section 121(b) of the NGPA deregulates the natural gas described in sections 107(c)(1), (2), (3), and (4) on November 1, 1978, (the effective date of the incremental pricing rule required under section 201) the Commission finds good cause to make this rule effective on November 1, 1979. However, since the public has not had a full opportunity to comment on all aspects of the rule, it is being issued as an interim rule and comments will be accepted through the close of business on November 26, 1979. If the additional comments received convince the Commission that amendments to this rule are appropriate they will be issued in the final rule. If no amendments are adopted this rule will become effective as a final rule and such notice will be published in the Federal Register.

Interested persons may submit comments concerning this interim rule by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, on or before November 26, 1979. Each person submitting a comment should include his name and address, identify Docket No. RM79-44, and give reasons for any recommendations. An original and 14 conformed copies should be filed with the Secretary of the Commission. Comments should indicate the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426, during regular business hours.

The Commission intends to hold a public hearing on this interim rule, as required by section 502(c) of the NGPA. The date and location of such hearing will be announced shortly. The regulations proposed in this interim rule shall not become final until the Commission has had an opportunity to receive oral presentation of relevant data, views and arguments.

In consideration of the foregoing, Subchapter H, Chapter I, title 18, Code of Federal Regulations, is amended by adding a new Part 272 and revising Part 274 as set forth below, effective as an interim rule November 1, 1979.

By the Commission. Commissioner Sheldon was present for the quorum and not voting.

Kenneth F. Plumb,
Secretary.

[¶ 30,095]

44 F. R. 61953 (October 29, 1979)

18 CFR Part 294

[Docket No. RM79-52]

Interim Procedures for Shortages of Electric Energy and Capacity Under Section 206 of the Public Utility Regulatory Policies Act of 1978; Amendment

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Amendment to interim regulations.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts regulations which extend through a period ending April 30, 1980 its interim regulations implementing procedures for shortages of electric energy and capacity under section 206 of the Public Utilities Regulatory Policies Act of 1978. Under the regulations as amended, each public utility now serving firm power wholesale customers must report to the Commission, the utility's customers, and appropriate State authorities any shortages of electric energy or capacity

anticipated to occur prior to April 30, 1980. Also, the regulations require each public utility to report any modification of its plans for accommodating shortages anticipated to occur before April 30, 1980.

EFFECTIVE DATE: October 23, 1979.

FOR FURTHER INFORMATION CONTACT:

Adam Wenner, Office of General Counsel, 825 North Capitol Street NE., Room 8104-C, Washington, D.C. 20426, (202) 357-8033.

Susan Tomasky, Office of General Counsel, 825 North Capitol Street NE., Room 8100-E, Washington, D.C. 20426, (202) 357-8033.

October 23, 1979.

On June 15, 1979, the Commission issued interim regulations[1] implementing in part Section 206 of the Public Utilities Regulatory Policies Act of 1978 (PURPA). Section 206 of PURPA amends the Federal Power Act to require public utilities to report to the Commission anticipated shortages of electric energy or capacity and to submit to the Commission and to appropriate State authorities contingency plans to accommodate any shortages which may occur prior to September 30, 1979.

Paragraph (b) of the interim regulations requires each public utility serving firm power wholesale customers to submit by July 23, 1979, a "brief statement indicating how it would accommodate any shortages of electric energy or capacity affecting its firm power customers, should such a shortage occur prior to September 30, 1979."[2]

Paragraph (c) of the interim regulations requires each utility to report immediately any shortage of electric energy or capacity which the utility anticipates will occur. In that report the utility must provide the Commission with certain information, including information regarding any procedures for accommodating a particular shortage, if they differ from the procedure set out in the utility's statement submitted pursuant to paragraph (b) of the interim regulations.

Initially, the interim regulations were intended to deal with shortages anticipated to occur prior to September 30, 1979. For this reason, paragraph (a) provides a limited definition of "anticipated shortages of electric capacity or energy", which includes only those situations which will result in shortages "anticipated to occur prior to September 30, 1979." The purpose of this amendment is to extend the reporting requirements for a period ending April 30, 1980, so that the Commission will be advised of any anticipated shortages which may occur during the winter period.

Accordingly, the Commission hereby amends the interim regulations as follows: first, the reporting requirements of paragraph (c) are extended through April 30, 1980, by amending the definition of "anticipated shortages of electric energy or capacity" in paragraph (a) to include those situations anticipated to occur prior to April 30, 1980. Second, if a plan to accommodate a shortage occurring prior to April 30, 1980, differs from the plan submitted pursuant to paragraph (b) of the interim regulations, the utility is hereby required to file a supplemental statement setting forth those changes. A utility need not file a statement of its plan to accommodate shortages prior to April 30, 1980, if that plan does not vary from that set out in the statement already filed pursuant to § 294.101(b).

(Public Utility Regulatory Policies Act of 1978, Pub. L. 95-617, 92 Stat. 3117; Federal Power Act, 16 U.S.C. 792 *et seq.*; E.O. 12009, 42 FR 46267; Administrative Procedure Act, 5 U.S.C. 553).

In consideration of the foregoing, Part 294 of Subchapter K, Chapter I, Title 18 of the Code of Federal Regulations is amended as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

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[1] Interim Regulations, Docket No. RM79-52 (issued June 15, 1979).

[2] This language was adopted by an Amendment to Interim Regulations, Docket No. RM79-52 (issued August 1, 1979) in order to make clear the Commission's intent that all public utilities serving firm customers must submit plans to accommodate any possible shortages. Before this amendment, the language appeared to suggest that only those utilities which anticipated shortages prior to September 30, 1979, were obliged to file accommodation reports under section 206 of PURPA.

[¶ 30,096]

44 F. R. 62484 (October 31, 1979)

18 CFR Part 281

[Docket No. RM79-40; Order No. 55]

Natural Gas Curtailment; Interim Regulation Governing the Determination of Alternative Fuels for Essential Agricultural Users

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Interim Regulations.

SUMMARY: The Commission is amending Part 281 of its regulations by adding a new Subpart C that prescribes which fuels the Commission has determined to be economically practicable and reasonably available as a substitute for the essential agricultural use of natural gas during the 1979–1980 winter heating season and how certain essential agricultural users of natural gas must remove from their priority 2 entitlements those volumes of gas for which there is an alternative fuel. The rule applies only to: (1) Essential agricultural use establishments that have requested from any direct supplier, over 300 Mcf of natural gas per day as a priority 2 entitlement; and (2) new boilers with a capacity of 300 Mcf per day, except diesel engines and turbines that can only use distillate fuels as a substitute for natural gas. The application of the rule is limited to the use of coal or residual fuel oil as alternative fuels.

This rule is promulgated under section 401(b) of the Natural Gas Policy Act of 1978 which restricts the protection from curtailment afforded under the Act by excluding from that protection any gas applied to essential agricultural uses, where there are other economically practicable and reasonably available fuels for those uses.

Direct suppliers must request of each essential agricultural user a statement computing its ability to use alternative fuels as a substitute for natural gas. The request must be made by November 7, 1979, and essential agricultural users must respond by November 23, 1979.

Under the interim rule, interstate pipelines will receive sufficient information from customers in the next six weeks to be able to amend their indices of entitlement by downgrading certain volumes now classified as priority 2. New indices must be filed by December 24, 1979.

EFFECTIVE DATE: October 26, 1979.

FOR FURTHER INFORMATION CONTACT:
MaryJane Reynolds, Federal Energy Regulatory Commission, Office of the General Counsel, 825 North Capitol Street NE., Room 8000, Washington, D.C. 20426, (202) 357-8455.

October 26, 1979.

I. Background and Summary

A. Statutory Background

Under Section 401(b) of the Natural Gas Policy Act (NGPA), the protection from curtailment required by section 401(a) does not apply to essential agricultural uses "if the Commission, in consultation with the Secretary of Agriculture, determines, by rule or by order, that use of a fuel (other than natural gas) is economically practicable and that the fuel is reasonably available as an alternative for any agricultural use of natural gas * * *."

On August 29, 1979, the Commission issued a second proposed rule in this docket which set forth a generic rule for the determination of alternative fuels for essential agricultural users as provided under Section 401(b) of the NGPA (44 FR 51993, September 6, 1979). The statute requires that the determination be made after consultation with the Secretary of Agriculture. The Commission has consulted with Agriculture and the written comments from Agriculture have been placed in the public files. However the Commission is aware that consultation does not necessarily result in full agreement. A public hearing was held on September 24, 1979, and 10 interested persons addressed the proposed rule. Written comments were filed by more than 70 interested persons including representatives of pipelines, distributors, agricultural users, industrial users, State commissions, and Members of Congress. Based on the record developed in this proceeding, the Commission has decided to adopt the rule essentially as proposed, with some modifications to be described.

This rule establishes that the alternative fuel determinations will be made using a generic rule. It further holds that during the forthcoming winter heating season, residual fuel oil and coal can be regarded, for purposes of administration of Title IV of the NGPA, as economically practicable and reasonably available as an alternative fuel to natural gas for those essential agricultural users who have the installed capability to use such fuels. No such finding is made with respect to any other fuel.

Unlike the proposal, the alternative fuel determination promulgated by this final rule will affect only to those agricultural establishments with requirements in excess of 300 Mcf of natural gas per day from a direct supplier.[1] There are several other changes from the proposed rule which are discussed below.

The immediate effect of this rule is that certain users of natural gas who qualify for priority 2 requirements in accordance with Order No. 29 [2] will have their requirements downgraded to a lower priority. The rule also applies to curtailment plans in effect after January 1, 1980, that deviate from Order No. 29 as a result of adjustment and settlements approved by the Commission that allows certain pipelines to implement plans that are different from the type of plan prescribed in Order No. 29.

The major issues raised in the proceedings on the proposed generic rule were the availability of residual fuel oil and distillate and the economic practicability of these liquid heating oil fuels as an alternative to natural gas.[3] Other issues that received considerable attention were the propriety of limiting the alternative fuel rule to those users who have installed capability, the creation of a small volume users exemption and the exclusion from the rule of those who use natural gas for non-boiler fuel uses. Many comments addressed the appropriate timing for implementation of the rule. Some persons urged immediate implementation of the rule; others urged it be postponed until after the winter heating season.

In response to comments, the final rule clarifies that the volumes downgraded from priority 2 are *only* those volumes for which residual fuel and coal can be substituted. Further the rule is modified to include a small volumes exemption. The rule will apply only to the essential agricultural users which use in excess of 300 Mcf of natural gas per day at any essential agricultural use establishment. The definition of new boiler is amended to include all turbines and diesel engines except those designed to use middle distillates as the only alternative to natural gas.

II. Discussion of the Major Issues and Comments

A. A Generic Rule

The rule adopted today is a generic rule, which makes two determinations. First, the rule prescribes a general procedure by which the Commission will henceforth make findings as to the availability of alternative fuels. Second, the rule finds that coal and residual fuel oils are economically practicable and reasonably available for the winter heating season of 1979–1980.

Some commentators were apparently misled by the proposed rule of August 29 which proposed a generic rule. They were of the view this rule constituted a rebuttable presumption, not a generic rule. Other essential agricultural users and the Secretary of Agriculture argued that the rule should be a rebuttable presumption.

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[1] The rule also applies to certain new agricultural boilers with a capacity in excess of 300 Mcf.

[2] Final Regulation for The Implementation of Section 401(a) the NGPA, Docket No. RM79-15, issued May 2, 1979 (44 FR 26855, May 8, 1979).

[3] The first proposed rule issued in this docket on May 2, 1979, set forth a procedure for the determination of alternative fuel. (44 FR 26894, May 9, 1979.) That proposal would have required all essential agricultural users to file economic and supply data. Based on the information filed the Commission would have subsequently issued a proposed rule which determines the reasonable availability and economic practicability of alternative fuel on a facility-by-facility basis.

The first proposed rule in this docket, issued on May 2, 1979, would have provided for a facility-by-facility determination of alternative fuel availability. However, many representatives of groups of essential agricultural users opposed the rule because they asserted that filing the information necessary for such a determination would be burdensome. These agricultural representatives, as well as other interested persons, urged the use of a generic rule. The Commission accepted this counsel and issued the second proposed rule on August 29, which set forth a generic rule. Now many of those who advocated a generic rule want the Commission to adopt a rebuttable presumption.

A rebuttal presumption is administratively infeasible, particularly if there is to be an alternative fuel rule in place for this winter heating season. Moreover, any person who no longer qualifies for priority 2 classification because of alternative fuel may seek an adjustment in accordance with section 502(c) of the NGPA and the adjustment procedures in 18 CFR 1.41. Any person who experiences special hardship, inequity or unfair distribution of burdens because of the rule may seek an adjustment which modifies the rule as applied to such person or exempts the essential agricultural user from the rule. Moreover, any person who seeks adjustment relief may simultaneously seek interim relief which could provide such petitioner with the ultimate relief on an interim basis before a decision has been made on the merits of the petition for adjustment relief.

We recognize that if the Commission did adopt a rebuttable presumption in lieu of a generic rule, that the standards for exclusion from the rule could differ from the section 502(c) standards. It would also involve numerous factual determinations which could be administratively burdensome to resolve in an expeditious manner. Thus, use of a rebuttable presumption could cause substantial delay in implementation of an alternative fuel rule.

The Commission has received comments from various parties [4] requesting assurance of priority 2 entitlements for natural gas used to process "gasohol". The participants note that an assured entitlement is required before distillers will incur the expense of retrofitting their plants to produce the fuel grade alcohol.

It is our belief that it is inappropriate to address this problem in an interim rule. Further, the comments note that retrofitting requires at least six months to accomplish and this interim rule will terminate after this winter heating season.

The Commission is aware of the President's and Congressional interest to develop alternate fuels to motor gasoline. As such, the Commission believes it would be preferable to inquire into the desirability of establishing a long-term determination concerning the alternative fuel availability for gasohol in a separate proceeding.

B. Availability of Fuels

The proposed rule envisioned a Commission determination for this winter heating season that coal and residual fuel oil were "reasonably available" as that term is used in the alternative fuel provision in section 401(b) of the NGPA. It stated further the Commission believes it lacks the relevant basis for a finding that distillates would be reasonably available this winter. There was no significant debate as to the finding of the availability of coal. The Commission finds, based on the data presented in response to the proposed rule of August

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[4] Among those expressing interest in furthering the distillation of "gasohol" were 18 members of the United States Senate.

29, that coal is a reasonably available fuel.

In contrast, the positions on the availability of liquid fuels proved this to be a devisive issue. Those opposing a finding that any liquid fuels are available noted a general "nationwide shortage of crude oil."

The proposed rule indicated that the Commission did not believe that it had the requisite information to find that middle distillates were reasonably available for this coming winter heating season. The conclusion was supported by numerous statements by the Secretary of Energy and the Deputy Secretary who cited various Department of Energy (DOE) data concerning inventories of middle distillates. They expressed concern about the risks involved and established a target inventory of 240 million barrels at the start of the coming heating season. Over the course of the summer when middle distillate inventories (primary, secondary and tertiary) are historically stockpiled, the DOE data indicated dramatic shortages in primary supplies and a lag in the rates of stockpiling of secondary supplies. As a result, it may be that the buildup of tertiary supplies (summer fill of home and commercial heating oil tanks) was not completed. Recently, the DOE has issued statistics that indicate that primary stocks of middle distillates have reached the desired target for acceptable supplies. Current data is not available on secondary and tertiary supplies.

Thus, as this final rule is promulgated, there is reasonable cause for guarded optimism about the United States heating oil situation. As noted, the DOE guideline inventory target for primary supplies seems to have been achieved. The economic downturn has significantly lessened demand and should an economic recession ensue this winter's demand should be even further reduced. Conservation efforts and higher oil prices are having an effect. This winter may not be as cold as the last several.

On the other hand, the crude oil situation is extremely troublesome. A very key element in the prediction about the winter heating oil supply and demand balance is the assumption that refineries will be able to obtain sufficient crude oil imports. In this respect, the confused and uncertain international oil market is a cause for great concern.

Put differently, the question of the "adequacy" or "reasonable availability" of heating oils for the forthcoming winter is a matter of predicting the level and interaction of a variety of complex and uncertain variables. Projecting how these variables will balance out is a risky task and on several previous occasions the Commission has declared its belief that caution and prudence in making decisions based on such projections is the appropriate posture.[8] Misjudgments that might have the unintended consequence of creating unanticipated additional demands for home heating oil this winter when the pertinent markets are in such an uncertain and changing condition should be avoided. In sum, the Commission continues to believe that in this period of significant change in fuel markets it should approach decisions that might create additional and unexpected demands for home heating oil with caution and avoid stimulating unintended exacerbation of the current scramble for heating oil supplies and the already impressive and disturbing run-up in heating oil prices.

In light of these policy considerations, especially the risk to home heating oil consumers this winter of misforecasts and despite guarded optimism about supplies this winter, we find that the data and information in the present record do not provide the requisite basis for the statutory finding of reasonable availablity of distillate fuel oil for this winter.

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[8] Most recently, in Order No. 51, dealing with incremental pricing of natural gas, the Commission determined, subject to Congressional review and possible veto, that the current situation implied that it would be preferable for an interim period covering the current heating season to place the incremental ceiling price at the cost of No. 6 oil to minimize the risk of load shifting from natural gas to heating oil. Among the reasons for this judgment was concern about the impact on heating oil markets. The Commission stated: "Moreover, the shifted load would place a demand on fuel oil markets this winter that could have undesirable consequences." Order No. 51, Docket No. RM79-21 issued September 28, 1979, at 18 (44 FR 57778, October 5, 1979).

The reasonable availability of residual fuel oil is a more difficult matter. As some commentators noted, and as just discussed, the crude oil situation remains tight and problematical. There is a national effort of highest priority to reduce imports. Also, as we noted in connection with Order Nos. 30 and 30–A[6], all fuel oil markets are closely linked. On the other hand, stocks of residual oil are reasonably comfortable and the relevant markets seem more stable. Consequently, we believe that there has been the requisite basis established in this proceeding for a Commission determination that for this winter residual fuel oil is readily available pursuant to section 401 of the NGPA. To the extent that local shortages of residual fuel oil manifest themselves this winter, a situation that concerned a number of commentators, the Commission stands ready to act under section 502(c). They also pointed out that the President announced a ceiling on oil imports at the Economic Summit in Japan this summer. A large share of the residual fuel oil consumed in this country is imported. They concluded that the basis exists for a finding that all liquid fuels are not readily available.

However, there are contrary facts that tend to indicate a different supply picture. Notwithstanding the general shortage of domestic crude oil, because of imports, refineries have been operating at a relatively high level of capacity. During the four week period ending September 28, 1979, they have operated at an average capacity of approximately 84 percent. The Commission is cognizant of the import quota policy the President announced in July. It is not known whether the policy will limit imports of residual fuel oil. Some persons alleged there are spot or regional shortages of residual fuel oil but failed to support the claims with data.[7] Thus, based upon the record, the Commission finds that residual fuel oil is reasonably available.

The proposed rule did not address the availability of propane because of a lack of data on this matter. Accordingly, propane will not be found to be reasonably available for this winter heating season. The Department of Energy is presently conducting a rulemaking proceeding addressing decontrol of propane. (44 FR 50072, August 27, 1979). Information may be developed in that rulemaking which would allow the Commission to consider the availablility and economic practicability of propane when it reviews all fuels after the winter heating season.

C. Economic Practicability

For purposes of the rule, the Commission may properly limit the scope of its inquiry to the economic practicability of those fuels found to be reasonably available—coal and residual fuel oil. As indicated in the preamble to the proposed rule, coal is generally less expensive than natural gas and no issue has been raised as to the economic practicability of using coal for those facilities which have installed capability to use coal.

The economic practicability of residual fuel oil is another matter. The relative cost of residual fuel oil as presented in the proposed rule was not seriously rebutted by any subsequent comment filed in this proceeding. The proposed rule found that residual fuel oil usually costs up to 50 percent more than the cost of natural gas.[9] The Commission believes that the use of residual fuel oil for the winter heating season is economically practicable. The Commission does not expect this action will cause "unnecessary increases in the cost of food." A finding that residual fuel oil is a reasonably available and economically practicable alternative for those firms that have installed capacity indicates that increases in food costs contemplated by the statute do not seem likely.

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[6] Final rule, Transportation Certificates for Natural Gas for the Displacement of Fuel Oil, Docket No. RM79–34, issued May 17, 1979 (44 FR 30323, May 25, 1979); Order on Rehearing, Docket No. RM79–34, issued September 12, 1979 (44 FR 54472, September 29, 1979).

[7] In the event shortages of residual fuel oil materialize, affected persons may seek adjustment relief to release them from the alternative fuel rule.

In reaching this conclusion, the impact of the alternative fuel rule (in terms of reduction of deliveries of natural gas during the first year the curtailment rule is in effect) was considered. The alternative fuel rule will cause the downgrading of some requirements of the essential agricultural user to the pre-existing curtailment priority instead of the new priority 2 created by the NGPA. It is anticipated that, over the course of this winter, curtailment will not be severe. Therefore, there is small likelihood that an essential agricultural user will necessarily have extended requirements for using alternative fuel as the agricultural user had over the course of the last two winter heating seasons, even if such essential agricultural user is downgraded to his historic priority. Moreover, no alternative fuel rule was in place over the summer and none will be in place until January 1, 1980. Thus, the difference in the cost of residual fuel oil, vis-a-vis the cost of natural gas, does not necessarily mean that the total annual fuel costs for an essential agricultural user who has requirements removed from priority 2 will result in annual increased fuel costs of the same magnitude.

We have given much attention to that part of the extensive record in this proceeding where persons have alleged that regarding residual fuel oil as an alternative fuel would produce economic difficulty in the agricultural sector. Very little economic data or persuasive factual analysis has been presented. Discussion of the issue was generally limited to a comparison in the costs of fuels. The essential agricultural users contesting the finding of economic practicability of residual oil failed to establish that the use of such oil would increase food costs significantly or unreasonably. For these reasons, the Commission believes that residual fuel oil is economically praticable for the course of this winter's heating season.

The Commission stresses that this rule finds that residual fuel oil and coal are economically practicable for this winter only for those essential agricultural users who presently have installed ability to use such fuels. There is no requirement for incurring conversion costs.

Certain essential agricultural users argue that, even though they have in fact the installed capability and have in fact used either residual fuel oil or coal they do not have adequate storage to use alternative fuel oil for all requirements. The effect of a finding that such essential agricultural users have alternative fuel merely downgrades their priority of service category. As noted above, it does not force them to turn to the alternative fuel for 100 percent of their energy requirement. It is anticipated that gas supplies this winter will be as good or better than in the last several winters. It follows, that essential agricultural users who had adequate storage to meet the exigencies of curtailment in recently past winters will, in large measure, have adequate storage to meet the exigencies of this winter caused by being downgraded from priority 2.

D. *Ability To Use Alternative Fuel*

The test for the ability to use an alternative fule is twofold. The essential agricultural user must have installed capacity (as of the date of the proposed rule) to use the alternative fuel and it must have, in fact, used such fuel at some time since 1973. Several issues have been raised about this test. Some persons assert that environmental constraints will prevent them from using fuels that they have used in the past. Others have suggested that they experienced a reduction in quality of the product which is made by use of the alternative fuel. The Commission does not believe that either of these problems countervail the efficacy of the rule. Where laws or regulations no longer permit the use of the alternative fuels or where the use of alternative fuel would result in an inferior product, adjustment relief may be sought from the Commission in accordance with the adjustment procedures in 18 CFR 1.41.

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[9] Some persons argued that the Commission should issue a general standard by which it will measure economic praticability. The Commission finds that doing so would be premature at this time. Those persons who believe this rule will cause them hardship, inequity or an undue burden may seek an adjustment. In such a proceeding, the Commission would consider the cost the alternative fuel rule has on the food prices as a relevant factor.

Some persons suggest that the ability to use an alternative fuel should be based on actual use over a more extended period of continuous use than one day. The intent of the one day test is merely to establish the ability to use. A more extended test appears to be advocated in order to ensure against potential storage problems.

A number of parties alleged that the rule is unfair because it appears to penalize those essential agricultural users that have installed alternative fuel capability for the use of coal or residual fuel oil. These persons will be downgraded from priority 2 while those persons who failed to take measures to use coal or residual fuel oil in the face of severe natural gas shortages over the course of the last six years will not be required to downgrade. The Commission recognizes the inequity in downgrading only those facilities which have installed capability. Nonetheless, this is an interim rule and the Commission believes that it is impossible for essential agricultural users who have not installed alternative fuel capability to do so over the course of this winter. Therefore, the Commission does not believe it can downgrade essential agricultural users who do not have installed capability. It has not yet been determined if the Commission can find alternative fuel to be economically practicable at some subsequent time in those cases where the essential agricultural user has never installed alternative fuel capability. However, conversion costs would be a relevant factor in the Commission's determination of economic practicability. The Commission wishes to put essential agricultural users on notice that it has not determined whether it will be able to find an alternative fuel economically practicable for those users who have not presently installed alternative fuel capability.

E. Small Volume Exemption

The Commission believes it would be administratively burdensome and impracticable to gather the data concerning essential agricultural users under 300 Mcf per day and have the alternative fuel rule in place for this winter. Therefore, the Commission believes it is appropriate to limit the alternative fuel test only to those essential agricultural use establishments of an essential agricultural user—on a facility by facility basis—which requested in excess of 300 Mcf of natural gas per day from a direct supplier. This is consistent with past Commission policy on large users.[9] The alternative fuel rule also provides that new boilers with capacity in excess of 300 Mcf per day other than diesel engines and gas turbines that use distillate oil, are deemed to have alternative fuel capability. We stress that both the questionable supply of distillates and the fact that the time lapse between design of a boiler and the placement onstream of the new boiler is such that it would be impracticable to apply the presumption of the new boiler test to all boilers for the course of this winter. However, the Commission reserves the right at some future time to reevaluate the question of allowing new boilers which are designed solely to use distillates in lieu of natural gas to obtain a priority 2 preference as essential agricultural users.

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[9] The Commission stresses that after this winter heating season it may not feel constrained to classify large users as only those over 300 Mcf per day

F. Limitation of the Rule to Boiler Users

Some persons have suggested that the alternative fuel rule be limited exclusively to boilers. The Commission sees no evidence in the record which supports the distinction between the boiler fuel use and any other use of natural gas by persons who are able to use coal or residual fuel oil. Nor does it perceive any public policy benefit from a rule which gives a preference to users who are able to use coal or residual fuel oil. Therefore, the rule shall apply to all users of residual fuel oil or coal and not just to boiler fuel users.

G. Timing of the Rule

The Commission is fully cognizant of the significant fluctuations in the liquid petroleum market. These fluctuations can affect either supply or price or both. Accordingly, the Commission is herein issuing an interim rule and will address the issues of availability and economics anew at the end of the winter heating season.

A number of persons have advocated that the rule should not be effective over the course of this winter's heating season because it will create problems for essential agricultural users who relied on obtaining natural gas under the priority 2 preference in Order No. 29. The Commission has stated frequently since January, 1979 that an alternative fuel rule would be forthcoming for essential agricultural users. In May, it was announced that the Commission intended to have an alternative fuel rule in place for the winter heating season. Moreover, the Commission is cognizant that granting a priority 2 preference to essential agricultural users who are able to use residual fuel oil or coal would further jeopardize the availability of natural gas to process and feedstock users. Accordingly, the Commission finds good cause to issue the alternative fuel rule with an immediately effective date. The Commission notes, however, that it will take time to gather the data necessary to adjust the index of entitlements to exclude those essential agricultural users who do have the ability to use alternative fuel, as defined in this rule. Accordingly, this rule will not require the amendment of the indices of entitlements by interstate pipelines (which could result in excluding from priority 2 deliveries to essential agricultural users of volumes for which an alternative fuel is available) until January 1, 1979. This lag in the date upon which the alternative fuel determination will affect the availability of natural gas will give those facilities with installed alternative fuel capability, that have had notice of the proposal since at least August, 1979, three additional months to make arrangements for residual fuel oil or coal for this winter's heating season.

It is the Commission's preliminary view that an environmental impact statement is not necessary. However, the Commission has not completed its evaluation of the effects this rule could have upon the environment. If, upon the completion of its evaluation, the Commission believes an Environmental Impact Statement ("EIS") is necessary, it will undertake to prepare an EIS and will complete it before issuance of a permanent rule.

III. Discussion of Substantive Changes in the Final Rule from the Proposed Rule

A. Data Gathering for Purposes of Implementing the Rule

The draft rule would have required that each essential agricultural user affected by this rule advise its direct supplier of its alternative fuel availability for either residual fuel oil or coal. After receipt of the information the direct supplier would transfer the information up the stream to the interstate pipeline suppliers. The interstate pipeline suppliers would adjust the index of requirements to exclude such essential agricultural users from their priority 2 treatment.

In light of the difficulty experienced in gathering data with respect to the requirements of essential agricultural users under Order No. 29, which implemented the permanent curtailment plan, the Commission has determined it would be more appropriate to place the initial burden of gathering the information about alternative fuel volumes on the direct suppliers of such essential agricultural users. The essential agricultural users must, upon request of their direct suppliers, provide an amended request for priority 2 entitlements which excludes any volumes for which alternative fuel could be used. The user must also submit an oath statement that the amended request excludes all volumes for which it has an ability to use alternative fuels. If, in fact, an essential agricultural user refuses to provide the oath statement, the distribution company may presume that such essential agricultural user has the ability to use an alternative fuel. The essential agricultural user, using the attribution rule of Subpart B, in § 281.209, shall forward the information concerning the decrease in priority 2 requirements to its supplier.

B. Small Volume Exemptions

As discussed more fully above, the Commission does not believe it is administratively feasible to include all essential agricultural users in this first alternative fuel rule. Accordingly, the alternative fuel rule will apply only to those essential agricultural users that have requested, on behalf of an essential agricultural use establishment, natural gas in excess of 300 Mcf per day from a direct supplier.

C. Calculations of Volumes To Be Downgraded

A number of comments were raised which indicated that the volume of natural gas to be downgraded from priority 2 because of alternative fuel availability was unclear. The rule has been clarified but the intent remains unchanged. An essential agricultural user must downgrade its priority 2 requirements to exclude from priority 2 any natural gas for which its essential agricultural use establishments have the ability to use alternative fuel, as defined in this subpart. Assume an essential agricultural user that has requirements of 1,500 Mcf per day of natural gas at a particular essential agricultural use establishment. Of that amount, 1,000 Mcf will be used as boiler fuel and 500 Mcf of this natural gas for which priority 2 classification is requested is used directly as a process fuel for which there is no installed capability to use an alternative fuel. Assume further that the essential agricultural user has installed ability to use either coal or residual fuel oil for 2,000 Mcf for boiler fuel requirements. In that situation, the essential agricultural user would downgrade 1,000 Mcf of natural gas for that establishment from priority 2 because of the alternative fuel rule. The essential agricultural user would retain 500 Mcf in priority 2 for process fuel for the establishment.

D. Definition of Boiler

The definition of boiler has been amended. A new boiler is not subject to the alternative fuel rule if it is a diesel engine or gas turbine designed to use middle distillates as the exclusive alternative to natural gas.

E. Filing Requirements

Section 281.305 of the proposed rule required essential agricultural users with requirements in excess of 300 Mcf per day to file certain information concerning their use of fuel other than natural gas. The Commission believes this information is essential for its future administration of section 301 of the NGPA and the essential agricultural curtailment rule. However, to avoid confusion, this filing requirement, which is in large part a data gathering exercise, will be promulgated as a separate subpart at a subsequent date.

IV. Section-by-Section Summary of the Interim Rule

Purpose (§ 281.301). This section states that it is the purpose of the Subpart C (§§ 281.301–.305) to determine the economic practibility and reasonable availability of alternative fuels for use by certain essential agricultural users of natural gas as a substitute for volumes of any natural gas for which the user is seeking a priority 2 entitlement in the curtailment plans of interstate pipelines.

Applicability (§ 281.302). This section applies to any essential agricultural use establishment, as defined in § 281.303, for which an essential agricultural user requested priority 2 entitlements for natural gas under § 281.207, in volumes over 300 Mcf per day from any single direct supplier, and to any new boiler of such an establishment that has a capacity of 300 Mcf of natural gas per day and is first put into service after August 29, 1979. Diesel engines and turbines that are designed to use distillate fuels as the only substitute for natural gas are not "new boilers" within the scope of the rule. The 300 Mcf limitation relates to an amount requested from a direct supplier on behalf of an essential agricultural use establishment, and indicates a total capacity, in the case of a new boiler.

Definitions (§ 281.303). This section defines the following terms as they are used in this subpart:

"Ability to use" a particular alternative fuel means that an essential agricultural use establishment had the installed physical capability on August 29, 1979, to use an alternative fuel and has used such fuel at some time since 1973 for an essential agricultural use.

"Alternative fuel" means coal or residual fuel oil.

"Boiler" means a fuel burning device used for generating steam or electricity or for producing hot water for space heating or manufacturing processes.

"Direct supplier" means the interstate pipeline or local distribution company that directly supplies natural gas to an essential agricultural use establishment, an interstate pipeline that directly supplies a local distribution company, and an interstate pipeline that directly supplies an interstate pipeline purchaser.

"Essential agricultural use establishment" has the same meaning as in the Department of Agriculture regulations, 7 CFR 2900.2, which reads, in pertinent part:

> (b) "Establishment" means an economic unit, generally at a single physical location where business is conducted or where service or industrial operations are performed (for example, a factory, mill, store, mine, farm, sales office, or warehouse). (Note.—This is the same definition used in the Standard Industrial Classification Manual, 1972 edition).
>
> (c) "Essential Agricultural Use Establishment" means any Establishment, or portion of an Establishment, which performs (or has the capability to perform) activities specified in § 2900.3.
>
> § 2900.3 Essential agricultural uses. For purposes of Section 401(c) of the NGPA the following classes or portions of classes are certified as essential agricultural uses in order to meet the requirements of full food and fiber production: * * *

An essential agricultural user, which ultimately requests priority classification for its deliveries of natural gas, may have more than one establishment in more than one location.

"Priority 2 entitlements" means the essential agricultural requirements that are classified by an interstate pipeline as priority 2 in its curtailment plan under Subpart B of the Commission's curtailment regulations.

This section also defines "capacity," "coal," "distillate fuel," "essential agricultural user," "local distribution company," and "residual fuel oil."

General Rule (§ 281.304). This section sets forth the method for calculating what volumes of natural gas of each essential agricultural user are subject to this alternative fuel rule. Paragraph (a) states that the alternative fuel volumes subtracted from the total agricultural requirements of an essential agricultural user under § 281.208 are the sum of the alternative fuel volumes of each essential agricultural use establishment for which such user requested priority 2 entitlements in excess of 300 Mcf per day. The alternative fuel volume for each essential agricultural use establishment is that portion of such establishment's requirements for which it has requested priority 2 entitlement and for which it had, on August 29, 1979, the installed capability to burn coal or residual fuel oil.

Paragraph (b) provides that any boiler of an essential agricultural use establishment put into service after August 29, 1979, and having a capacity over 300 Mcf of natural gas per day, will not receive a priority 2 entitlement for any volumes of natural gas. This generic rule for new boilers does not apply to diesel engines or turbines designed to use only Nos. 1 or 2 heating oil, diesel fuel, or No. 4 fuel oil, in addition to natural gas.

Filing of Amendments To Essential Agricultural Requirements and Priority 2 Entitlements (§ 281.305). Paragraph (a) places the responsibility on direct suppliers of an essential agricultural use establishment for requesting of each such establishment that requests of that supplier over 300 Mcf per day in priority 2 entitlements, that it notify the essential agricultural user of its alternative fuel volumes and that the user in turn submit an amended request for priority 2 classification and an oath statement on alternative fuel capabilities, under paragraph (b). The direct supplier must make the request by November 7, 1979. While the essential agricultural user and the use establishment may be the same entity, the establishment may be one of several parts of the user at one of several locations. The user normally requests priority classification for natural gas for each individual establishment.

By December 7, 1979, the direct supplier must transmit to the next direct supplier, whether an interstate pipeline or interstate pipeline purchaser, the information submitted to it by the essential agricultural user or other direct customer that reduces its essential agricultural requirements for natural gas. Computation and transmittal of the amended essential agricultural requirements must be performed in accordance with the attribution rule in § 281.209.

Paragraph (b) prescribes the responsibilities of an essential agricultural use establishment, for which more than 300 Mcf per day of priority 2 entitlements has been requested from a direct supplier, to reduce its essential agricultural requirements according to its ability to use an alternative fuel as determined under §281.304. The essential agricultural user must respond, by November 23, 1979, to the requests of any direct supplier under paragraph (a). The response must consist of an amended request for priority 2 classification of volumes of natural gas and an oath statement that the amended request contains no volumes of natural gas for which the establishment can use coal or residual oil.

Paragraph (c) states that failure of the essential agricultural user to respond to any direct supplier by November 23, 1979, will result in the irrebuttable presumption of alternative fuel capability for the establishment and will cause the direct supplier to subtract those volumes of natural gas classified as priority 2 from the essential agricultural requirements of the user, which requirements the direct supplier will transmit to its direct supplier.

Paragraph (d) requires interstate pipelines to amend the priority 2 classifications in the indices of entitlements according to the information about essential agricultural requirements as revised to accommodate the ability of end-users to use alternative fuels. The new indices must be filed by December 24, 1979 and have a proposed effective date of January 1, 1980.

Conforming Amendments. Sections 281.204(b)(3), 281.208(b)(1)(i)(B), and 281.211(b)(4) are revised to conform with the new Subpart C. These sections are in the regulations that set forth the basic procedures for establishing curtailment plans for natural gas classified as priority 1 and priority 2. They deal with the revision of indices of entitlement according to the alternative fuel determination, calculation of attributable priority 2 entitlements, and filing procedures for subsequent changes in priority 2 entitlements.

V. Effective Date

These regulations are being issued effective immediately on an interim basis. The Commission finds that the significant fluctuations in the liquid petroleum market prevents a long-range determination of what alternative fuels are economically practical and reasonably available as a substitute for natural gas. The Commission will therefore address the issue again at the end of the 1979–1980 winter heating season. The Commission finds good cause to waive the 30-day delay in the effective date under section 553 of the Administrative Procedure Act. In order that the interstate pipelines amend the indices of entitlements by the winter season, data on alternative fuels must be requested and transmitted to the pipelines in the next four to six weeks. In a curtailment situation, permitting priority 2 natural gas to be used this winter by essential agricultural users that are able to use coal or residual oil could jeopardize the availability of natural gas to process and feedstock users that do not have the ability to use alternative fuels. Moreover, the Commission has stated its intention to implement an alternative fuel rule on several occasions since January, 1979.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432; Department of Energy Organization Act, 42 U.S.C. 7101–7352; E.O. 12009, 42 FR 46267)

In consideration of the foregoing, Part 281 of Chapter I, Title 18 of the Code of Federal Regulations is amended as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,097]

44 F. R. 62889 (November 1, 1979)

18 CFR Parts 270 and 271

[Docket No. RM80-3]

Natural Gas; Publication of Prescribed Maximum Lawful Prices Under the Natural Gas Policy Act of 1978; Amendments to Final Regulations

Issued: October 24, 1979.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: This rule amends § 271.101(a) of the Federal Energy Regulatory Commission's regulations implementing the Natural Gas Policy Act of 1978 (NGPA). By this amendment, the Commission publishes the Maximum Lawful Prices under the NGPA for the months of November and December of 1979 and January of 1980. Section 101(b)(6) of the NGPA requires that the Commission compute and make available prices and inflation adjustments at least five days before the beginning of any month for which such figures apply.

EFFECTIVE DATE: October 24, 1979.

FOR FURTHER INFORMATION CONTACT: Mark Magnuson, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357–8511.

SUPPLEMENTARY INFORMATION:

A. Background

Section 101(b)(6) of the NGPA requires that the Commission compute and make available maximum lawful prices and inflation adjustments at least five days before the beginning of any month for which such figures apply. Pursuant to that mandate, the Commission is amending its regulations implementing the NGPA to issue the maximum lawful prices for the months of November and December of 1979 and January of 1980 by the publication of price tables for the applicable quarter.

Table I specifies the maximum lawful prices for gas subject to Sections 102, 103, 106(b)(1)(B), 107, 108 and 109 of the NGPA. Table II specifies the prices for Sections 104 and 106(a); Table III sets forth the inflation adjustments.

B. Summary of Amended Regulation.

The Commission's regulations under the NGPA are being amended by the publication of Tables I, II, and III establishing the maximum lawful prices and inflation adjustment factors for November and December of 1979 and January of 1980. This amendment affects the Subpart A of Part 271, entitled:

"Summary Tables and Calculations" (§§ 271.101(a) and 271.102(c)).

C. Public Procedure and Effective Date

The Commission is making these amendments effective upon the date of issuance of this order upon a finding that it is impractical and unnecessary to comply with the notice and public procedure provisions of 5 U.S.C. § 533. Section 101(b)(6) of the NGPA requires that maximum lawful prices and inflation adjustments be made available by the Commission at least five days before the beginning of the month to which they apply. However, publication of the GNP Implicit Price Deflator by the Department of Commerce at least 8 days before the most recent calendar quarter, does not provide sufficient time for comment before the maximum lawful prices and inflation adjustments go into effect. Notice and public comment are unnecessary as well as impractical because the changes do not change the substance of the regulations and because the changes in prices and inflation adjustments are mandated by statute. Good cause exists to make these amendments regarding the rate changes for November and December of 1978 and January of 1980, effective immediately. Such a procedure is required in order to comply with the NGPA, and, if such a procedure is not followed, producers may bill and file incorrectly for the affected categories of gas.

(Natural Gas Act, as amended, 15 U.S.C. § 717 *et seq.;* Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350; Department of Energy Organization Act, 42 U.S.C. § 7107, *et seq.,* E.O. 12009, 42 FR 46267)

In consideration of the foregoing, Part 271 of Subchapter H, Chapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,098]

44 F. R. 65055 (November 9, 1979)

18 CFR Parts 2 and 157

[Dockets Nos. RM79-37 and RM79-43]

Budget-Type Certificate Applications—Gas Purchase Facilities; Amendments to the Regulations Implementing the Natural Gas Act

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Commission expands the use of budget-type certificates for gas supply facilities by expanding the types of facilities eligible for such coverage and increasing the dollar limits for eligible facilities. The purpose and intended effect of this final rule is to decrease the administrative burden on the public and to facilitate more rapid increases in gas supplies for consumers.

EFFECTIVE DATE: December 1, 1979.

FOR FURTHER INFORMATION CONTACT: Frank Markulin, Office of Pipeline and Producer Regulation, 825 North Capitol Street, NE., Washington, D.C. 20426 (202) 357-8859. Bob Nichols, Office of the General Counsel, 825 North Capitol Street, NE., Washington, D.C. 20426 (202) 357-8141.

SUPPLEMENTARY INFORMATION:

Before Commissioners: Charles B. Curtis, Chairman; Matthew Holden, Jr., and George R. Hall.

In the matter of Budget-type Applications: Gas Supply Facilities—Amendments to Scope of Existing Regulations, Docket No. RM79-37; Amendments to Subpart A, Part 157 of the Regulations Implementing the Natural Gas Act, Docket No. RM79-43.

Order No. 56

Final Rule

Issued November 1, 1979.

The Federal Energy Regulatory Commission (Commission) amends

§ 157.7(b) of its regulations by changing the designation of "gas-purchase" facilities to "gas supply" facilities; increasing the maximum total annual and single project cost limitations for the construction of gas supply facilities; deleting the requirement of yearly filings of abbreviated applications; and changing the filing of completion reports under § 157.7(b) to a calendar-year basis. Under this final rule, "gas supply facilities" will include four types of facilities: (1) those necessary to connect gas supplies purchased from a producer or other similar seller; (2) those necessary to connect a pipeline's own production; (3) those necessary to connect gas acquired for system supply under sections 311 or 312 of the Natural Gas Policy Act of 1978, Pub. L. No. 95-621 (NGPA); and (4) certain facilities needed to transport or exchange natural gas. In doing this, the Commission is consolidating Docket Nos. RM79-37 and RM79-43.

A. Background and Description of Proposed Rule

Since its inception in 1956, the budget-type certificate has served an important function by permitting expeditious construction of minor facilities necessary to connect sources of natural gas to the system supply of jurisdictional pipelines. Traditionally, only minor, routine facilities have qualified for this procedure. The limits imposed upon facilities eligible for budget-type certification have limited the rate impact of facilities built under budget-type certificates. The Commission determined in 1956 that it was not in the public interest to require the imposition of the full certification procedures applicable under section 7(c) of the Natural Gas Act (NGA) for routine construction. The budget-type certificate procedure has accommodated both the purpose of the regulatory requirements imposed by section 7 of the Natural Gas Act and the need to enable pipeline companies to construct minor, routine facilities with a minimum regulatory burden.

However, changing circumstances have required a revision of the regulations applicable to budget-type certificates. Dollar limits for such certificates were last raised in 1975. Since then, construction costs have increased substantially. Moreover, prior to this rulemaking, budget-type proceedings were not available for facilities constructed by interstate pipelines to attach company-owned production. In addition, the Natural Gas Policy Act of 1978 permitted interstate pipelines to acquire surplus gas supplies from intrastate pipelines. Prior to the Interim Rule issued in Docket No. RM79-43,[1] however, facilities constructed to take that type of gas into system supply would not have been eligible for budget-type certification. Relatively minor facilities could make significant supplies of additional gas available from either company-owned production or NGPA sources if construction could take place in a timely manner.

1. Dollar Limits on Budget-Type Certificates

Docket No. RM79-37[2] proposed that the yearly, overall budget-type certificate limit be increased to the lesser of \$20 million or 3 percent of the applicant's gas plant account (F.E.R.C. Account 101, Uniform System of Accounts Prescribed for Natural Gas Companies). The limit for applicants with Account 101 balances of less than \$16⅔ million was raised to \$500,000.

In addition, it was proposed that the limit for any single onshore project built under a budget-type certificate be raised to the lesser of 25 percent of the total amount of the abbreviated application or \$2.5 million. The limit for offshore facilities was proposed to be increased to the lesser of \$3.5 million or the total amount of the budget-type certificate.

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[1] "Amendments to Subpart A, Part 157 of the Regulations Implementing the Natural Gas Act"; Docket No. RM79-43, issued May 18, 1979.

[2] "Budget-type Applications: Gas Supply Facilities—Amendments to Scope of Existing Regulations"; Docket No. RM79-37, issued April 19, 1979.

2. Expanded Definition of "Gas Supply Facilities"

Docket No. RM79-37 also proposed the use of budget-type certificates for facilities used to connect company-owned production. Under the expanded definition of "gas supply facilities", budget-type certificates could be used whether the gas was acquired through company exploration, development and production, acquired in place, or developed and produced in conjunction with any other person.

The proposal also deleted the words "authorized by this Commission to make a sale of gas to a gas purchaser" which had previously qualified "independent producer or other similar seller." Since the NGPA allows certain sales without Commission authorization, it was proposed that the restrictive clause be deleted as no longer necessary.

After the rule in Docket No. RM79-37 was proposed, final regulations were issued to implement sections 311 and 312 of the NGPA.[3] An interim rule was issued in Docket No. RM79-43 to permit budget-type certification of facilities necessary to connect gas supplies acquired pursuant to section 311 or 312 authorization. Docket Nos. RM79-37 and RM 79-43 have been consolidated herein.

3. Requirement of Calendar Year Filings

Docket No. RM79-37 also proposed that all application for budget-type certificates be filed by October 1st of the year preceding the calendar year for which the certificate would be issued. This procedure was proposed so that completion reports filed at the end of each calendar year would provide a common data base for analysis in the on-going review of the dollar limits prescribed by § 157.7(b)(1).

B. Comments on Proposed Rule and Summary of Final Rule

1. Total Yearly Budget Certificate Limits. § 157.7(b)(1)(i)

Under § 157.7(b)(1)(i) as amended by this final rule, the dollar limit on the total amount of construction allowed each year under a budget-type certificate is the lesser of $20 million or 3 percent of the certificate-holder's gas plant account (Account 101). The yearly limit for companies having a gas plant account of less than $16⅔ million is $500,000.

Several comments stated that the limits specified in the proposed rule were insufficient. Two basic reasons were given for higher limits:

(1) Inflation has raised the cost of construction and will continue to do so;

(2) Constant dollar costs of facilities to gather a given volume of gas have increased dramatically for two reasons. First, more drilling is taking place in fringe areas. This requires more facilities to connect completed wells with existing pipeline systems. Second, pipelines now must attach more wells to secure a given volume of gas due to present smaller reservoir size and consequent lower production per well.

The comments suggested increasing the limit to $25 milion; raising it to the greater of $20 million or 3 percent of gas plant account; tying the limit to the Handy-Whitman Index; or having a 3 percent limit without a specific dollar limitation. The Commission has decided that the limits in the proposed rule adequately take today's higher costs into consideration. However, increased costs are not the sole concern. Operational, environmental, and consumer rate impacts are also concerns that require periodic Commission review of these limits. Budget-type certificates are not intended to cover all or even a substantial part of a pipeline's construction. A straight 3 percent limit could make budget-type certification available for substantial portions of a pipeline's yearly construction activities, including the construction of non-routine facilities. The Commission must scrutinize the construction and operation of facilities that would significantly affect either a pipeline's operations or costs. We are satisfied that the limitations embodied in this order would permit timely construction of minor facilities while at the same time assuring Commission review of those facilities that could have a significant impact.

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[3] Order Amending Part 284 and Issuing Subparts A, B, C, and E as Final Regulations", Docket No. RM79-75, issued August 30, 1979.

2. Single Project Limits § 157(b)(1)(ii)

This paragraph, as amended by this final rule, states that no single project may be constructed under a budget-type certificate if its cost is more than the limits specified. Under the rule proposed in Docket No. RM79–37, these limits would have related to the type of project being built and the total amount of the budget-type certificate granted. Under prior Commission practice, each budget-type certificate granted was for a specific dollar amount. The percentage factor in the onshore single project limit could easily be tied to the amount of the certificate. Under this final rule, the percentage factor in the single project limit will be tied to the certificate holder's total calendar year limit.

Several comments, while finding the $2.5 million onshore limit to be sufficient, argued that the $3.5 million limit for offshore facilities was insufficient for the following reasons:

(1) The increased length of offshore pipelines and higher costs attending their construction has increased the cost of any single project. As the search for new production goes farther offshore and wells must be drilled in deeper waters, connecting facilities must necessarily be laid in deeper environs. This presents technical and logistical problems that increase the cost of projects.

(2) The limits for onshore projects were proposed to be increased 66 percent while the limits for offshore facilities were proposed to be increased only 40 percent.

These comments suggested that the offshore limits be increased to amounts ranging from $3.5 million to $5 million. The Commission does not agree with these recommendations. Budget-type certificates are intended for minor facilities. Large projects are more likely to involve questions about adequacy of reserves, possible alternatives, adequacy of design, rate impact, and environmental factors that the Commission should review more thoroughly in full NGA section 7(c) proceeding. The $3.5 million limit defines the upper parameters of the cost of constructing offshore projects which will not significantly affect operating conditions or cost recovery.

3. Definition of "Gas Supply Facilities"—§ 157.7(b)(4)

Before the changes made in this docket, facilities constructed to attach natural gas purchased from independent producers or other similar sellers were eligible for budget-type certificates. Facilities built to connect gas supplies to be transported by an interstate pipeline for another interstate pipeline were also eligible for such certificates if the transportation was pursuant to prior Commission authorization. The proposed rules added two types of facilities to those eligible for such proceedings:

(1) Facilities necessary to connect company-owned production; and

(2) Facilities constructed to receive into system supply gas acquired by an interstate pipeline under NGPA section 211 and 312 authorization.

These additions brought within the definition of "gas supply facilities" any facility needed to attach gas supplies with the exception of facilities constructed to make purchases from: plants manufacturing synthetic gas; (2) plants gasifying LNG; or (3) another interstate pipeline's system supply.

a. *Facilities to effectuate transportation by one interstate pipeline for another interstate pipeline.* Some comments suggested that the definition be expanded to allow budget-type certification in circumstances where a seller must deliver gas to an intermediate interstate pipeline for the account of a purchasing interstate pipeline. These comments also requested that the Commission make transportation arrangements between interstate pipelines self-implementing. The authority for such transportation presently is authorized only after an NGA section 7 proceeding. Docket No. RM79-74[4] proposes to make transportation by one interstate pipeline for another self-implementing.

Should that rulemaking be finally adopted, the present definition will allow budget-type certification for facilities constructed to effect that transportation. The operative language in the definition is "* * * or the system of another pipeline company authorized to transport gas for or exchange gas with that interstate pipeline * * *." See § 157.7(b)(4)(i). The facilities must be constructed under the budget-type certificate of the pipeline building and operating the facilities, whether that pipeline is the transporter or the final recipient. § 157.7(b)(6).

b. *"Other Similar Seller".* Some comments suggested that the words, "independent producer or other similar seller", unduly restricted the use of budget-type certificates. Under prior practice, the term "other similar seller" included purchases from producing subsidiaries or divisions of other pipelines and purchases from jurisdictional gatherers.

However, it did not include facilities constructed to facilitate the purchase of gas from another interstate pipeline's system supply. "Other similar seller" also excluded from coverage by budget-type certificates facilities constructed to make purchases from plants manufacturing synthetic gas and plants gasifying LNG.

These inclusions and exclusions are continued in this final rule. Under this rule, budget-type certificates may also be used to construct facilities to connect gas acquired for system supply from intrastate pipelines.

c. *Facilities to connect an interstate pipeline's own production.* No comment dealt directly with the provision other than to concur in its adoption. However, some of the comments regarding "other similar seller" mentioned categories that would be included in this portion of the expanded definition. Facilities eligible for budget-type certification include those facilities necessary to connect a pipeline's own production as well as the production of its affiliates.

d. *NGPA section 311 and 312 natural gas.* The comments received in Docket No. RM79-43 all supported the Commission's interim rule allowing budget-type certificates for facilities constructed to facilitate NGPA section 311(b) and 312 transactions. All of the commenters, however, read the interim rule as excluding facilities constructed for section 311(a) transportation from budget-type certificate coverage. The comments were most concerned about three types of facilities:

(1) Facilities constructed and operated by an interstate pipeline to receive into its system supply natural gas transported to it by an intrastate pipeline under section 311(a)(2);

(2) Facilities used by an interstate pipeline solely to attach or deliver gas supplies it is transporting pursuant to section 311(a)(1) authorization;

(3) Facilities constructed by an interstate pipeline to provide transportation between an interstate pipeline acquiring natural gas for its system supply and an intrastate pipeline providing NGPA section 311(a)(2) transportation for the purchaser.

The facilities described in paragraph (1) are subject to the Commission's NGA jurisdiction. All facilities constructed by an interstate pipeline are subject to the Commission's NGA jurisdiction unless specifically excluded by statute. Pursuant to section 601 of the NGPA, part 284 of these regulations excludes from NGA jurisdiction only those interstate pipeline facilities constructed to effectuate transportation on behalf of an intrastate pipeline or a local distribution company. Facilities constructed by an interstate pipeline to receive gas into system supply do neither. These facilities are eligible for budget-type certificate coverage under this final rule.

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[4] Interstate Pipeline Transportation on Behalf of Other Interstate Pipelines; Docket No. RM79-74, issued August 27, 1979; 44 FR 51612 (9/4/79).

The facilities described in paragraph (2) are not subject to its NGA jurisdiction and would not require a section 7(c) certificate if the facilities were used *solely* for section 311(a)(1) transportation authorized by Commission rule or order. This is because that transportation is on behalf of an intrastate pipeline or LDC. Hence, there would be no need for coverage by the budget-type certificate procedure for these types of facilities.

As pointed out in Docket No. RM 79–75,[5] the facilities described in paragraph (3) may or may not be subject to the Commission's NGA jurisdiction. Under present Commission policy, those facilities are not subject to NGA jurisdiction if adequate nexus exists between the transporting interstate pipeline and the intrastate pipeline to render the transportation "on behalf of" the intrastate pipeline. If either title to the natural gas remains vested in the intrastate pipeline or an agency relationship exists between the intrastate pipeline and the transporting interstate pipeline during that transportation, the facilities to effect that transportation are not subject to the Commission's NGA jurisdiction. An NGA section 7(c) certificate would not be required for their construction and operation. Under this policy, the facilities are subject to the Commission's NGA jurisdiction if both title nexus and the agency relationship are between the two interstate pipelines and there is no other evidence that the transaction is on behalf of an intrastate pipeline. Such jurisdictional facilities are eligible for budget-type certificate coverage.

Of course, facilities constructed by an intrastate pipeline to connect natural gas to be transported by it under section 311(a)(2) authorization would be nonjurisdictional.[6]

Section 284.003 states that the NGA jurisdiction of this Commission does not apply to any transportation, sale, or assignment of natural gas in interstate commerce if that transaction is authorized pursuant to NGPA section 311 or 312. To be so authorized a transaction must comply with Part 284 of these regulations or be authorized by a particular Commission order. A more complete analysis of these jurisdictional issues may be found in Order No. 46.[7]

Parties wishing to determine whether a particular transaction meets the requirements of section 311(a) may request an interpretation from the Commission under the provisions of § 1.42.

e. *The definition of "gas supply facilities" in the final rule.* § 157.7(b)(4). After consolidation of Docket Nos. RM79–37 and RM79–43, it was apparent that all facilities necessary to connect gas supplies were included in the respective definitions except the three types mentioned previously. Facilities to attach a company's own production were covered in Docket No. RM79–37. Facilities to attach gas acquired for system supply pursuant to NGPA section 311(b) and 312 authorization were covered in Docket No. RM79–43. Facilities necessary to bring into system supply natural gas transported to a pipeline pursuant to NGPA section 311(a)(2) authorization would have been either (1) purchased from an independent producer or other similar seller; (2) acquired from an intrastate pipeline pursuant to section 311(b) or 312 authorization; or (3) part of the recipient's own production. Facilities "necessary to connect" such gas supplies are not limited to those which directly connect the recipient and the source of gas.

The definition of gas supply facilities in this final rule therefore includes any facility necessary to connect the system of an interstate pipeline company, or the system of another pipeline company authorized to transport gas or exchange gas with that interstate pipeline, to natural gas supplies destined for the system supply of that interstate pipeline company. § 157.7(b)(4)(i).

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[5] *Id.*, note 3.

[6] NGPA section 601; Docket No. RM79–75, supra.

note 3.

[7] *Id.*, note 3.

Gas supply facilities do not include facilities built to effect the acquisition of gas from another pipeline's system supply or from plants manufacturing synthetic gas or gasifying LGN. § 157.7(b)(4)(ii).

This simplification of the definition is merely editorial. The change in wording does not exclude from coverage any facility covered under the prior regulations, the rule proposed in Docket No. RM79-37, or the Interim Rule issued in Docket No. RM79-43.

4. Filing of Applications and Completion Reports—§§ 157.5(b) (3) and (5)

Several comments requested that the Commission allow government fiscal year filing of budget-type applications or that applicants be given a choice between fiscal year or calendar year filing. The Commission has decided that one yearly period is needed so that the completion reports will form a year-to-year data base for analysis in the periodic § 157.7(b)(1) limit revisions.

However, the Commission does agree that the yearly filing of budget-type applications is unnecessary. Budget-type certificates will now be granted for an indefinite time. Interstate pipeline companies may continue to construct facilities under their budget-type certificates as long as the conditions, limits, definitions and reporting requirements of § 157.7(b) are met. Paragraph (b)(5) of this section covers the filing of applications. Should a company decide to terminate its budget-type certificate, it should request such a termination in its last completion report.

Completion reports for each calendar year during which a company has a budget-type certificate are still required. These reports are due by March 1st of the following year.

Some comments suggested that the amount of information required on the completion reports be reduced or that the time period for filing be extended to 90 days after the end of the year. We disagree with these comments. All of the information requested is necessary to the preparation of a data base of sufficient breadth and depth to allow a valid determination of any necessary modification of limits. This information is also necessary to the Commission's oversight function. The data supplied in the completion reports must be broken down on a project by project basis. If this information is collected and recorded at the completion of each project, there should be no problem with meeting the March 1 deadline.

Although the Commission finds that use of the budget-type certificate is appropriate with respect to NGPA section 311 or 312 facilities, it wishes to monitor the use of that procedure for this area. Notice must be given to the Commission within 10 days of the commencement of use of any NGPA section 311 or 312 facility constructed under a budget-type certificate which has a cost associated with it of more than either $50,000 or 1 cent per MMBtu.

This notice should include only the cost of the facilities, the duration of the transaction, and the number of MMBtu of gas being purchased, assigned, or transported during the duration of the transaction. The information required by paragraph (b)(3) of this section should be included in the completion report for the calendar year of construction.

Several comments requested that short-term budget certificates should be available to those applicants who, in the middle of the year, need to construct facilities that were not anticipated by the previous October 1st. Since yearly filings of abbreviated applications are no longer required, this does not present a problem. Companies which do not have an outstanding budget-type certificate may apply for one at any time. Companies now holding valid budget-type certificates should apply for a new, rollover certificate at least 60 days before the lapse of the existing certificate.

Companies holding budget-type certificates granted for a one year period prior to the effective date of this rule should file a completion report for that certificate period within 60 days of its expiration. This report should comply with § 157.7(b)(3) as amended by this rule.

These companies, as well as companies applying for a budget-type certificate for the first time, will probably be granted certificates during the middle of a calendar year. The total dollar limit (the lesser of $20 million or 3% of gas plant account) for construction during the remainder of that first calendar year will be reduced to an amount which bears the same proportion to the limit specified in § 157.7(b)(1)(i) as the number of months remaining in that first calendar year bears to 12.

A completion report for the first year of construction under the budget-type certificate must be filed by March 1st of the following year. This completion report should bear clearly on its face notice that it is for a partial year. Thereafter, completion reports will be filed each March 1st for the preceding calendar year.

5. The Transitional Rule—§ 157.7(b)(7)

The transitional rule originally provided for the length and total amount of budget-type certificates granted prior to January 1, 1981. Since such certificates are now being granted for an indefinite period, there is no need for most of that provision. However, there is still the need to provide for the yearly limits and filing of completion reports for companies not now on a calendar year basis and for companies initially granted a certificate in the middle of a calendar year. These provisions are included in § 157.7(b) and (7) of the final rule.

There were many suggestions that the broader definition and higher limits be made applicable to existing certificates for construction commenced after the effective date of the Natural Gas Policy Act. We agree with these suggestions in part. The appropriate changes are embodied in the transitional rule.

The higher limits allowed by this rulemaking will not apply to existing certificates. These limits will apply to budget-type certificates granted after the effective date of this rulemaking.

Certificates existing on the effective date of this rule will expire on their respective termination dates. Certificates granted after the effective date of this rule will be for an indefinite period, subject to the Commission's reservation of the right to revoke such a certificate at any time.

The construction of facilities to connect an interstate pipeline's own production may be done under existing certificates, but only as to construction commenced after the effective date of this order.

The construction of jurisdictional facilities used to facilitate NGPA section 311 or 312 transactions may be done under existing certificates, but only as to construction commenced after May 18, 1979, the effective date of the interim rule issued under Docket No. RM79-43.

6. Deletion of § 2.58

Section 2.58 of the Commission's regulations, entitled "Budget-type certificate applications—gas purchase facilities", merely repeats the provisions of § 157.7(b). For this reason, this section of the regulations is being deleted.

(Natural Gas Act, as amended, 15 U.S.C. 717, *et seq.;* Natural Gas Policy Act of 1978, 15 U.S.C. 3301, *et seq.;* Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.;* E.O. 12009, 42 FR 46267.)

In consideration of the foregoing, Part 2 of Subchapter A, Chapter I, Title 18, Code of Federal Regulations and Part 157 of Subchapter E, Chapter I, Title 18, Code of Federal Regulations are amended as set forth below, effective 30 days from issuance of this order.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,099]

44 F. R. 65740 (November 15, 1979)

18 CFR Parts 35, 154

[Docket No. RM 77-22; Order No. 47-A]

Rate of Interest on Amounts Held Subject to Refund; Order on Rehearing Modifying and Clarifying Prior Order

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Order on Rehearing Modifying and Clarifying Prior Order.

SUMMARY: The Federal Energy Regulatory Commission denies the applications for rehearing of Order No. 47, and amends the regulations adopted therein to clarify the Commission's intent that, after October 1, 1979, compounding should apply to interest on refundable amounts which accrued both before and after October 1, 1979.

EFFECTIVE DATE: October 1, 1979.

FOR FURTHER INFORMATION CONTACT:

Dennis Melvin, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8572.

Clarence Burris, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8161.

November 8, 1979.

On September 10, 1979, the Federal Energy Regulatory Commission issued Order No. 47 in the above-referenced docket which established (1) a new, self-adjusting, compounded carrying interest rate on refunds, (2) a new, self-adjusting, compounded carrying charge rate on deferred purchased gas costs, and (3) a reduction in the number of required refund reports.

Applications for rehearing of this order were timely filed by Cities Service Gas Company, Indicated Producers, the Interstate Natural Gas Association of America, Michigan Wisconsin Pipe Line Company, Northern Natural Gas Company, Southern Natural Gas Company, Transcontinental Gas Pipe Line Corporation, United Gas Pipe Line Company, and Tennessee Gas Pipeline Company and Midwestern Gas Transmission Company and East Tennessee Natural Gas Company (jointly).

Most of the arguments raised by applicants were treated adequately in Order No. 47 and need no further discussion in this order. One point requires clarification.

Many parties are unclear as to whether the compounding feature adopted in Order No. 47 is to be applicable only to interest which accumulates from and after October 1, 1979, the effective date of Order No. 47, or is it also to be applied to interest which accumulated before October 1, 1979.

Compounding is intended to apply after October 1, 1979, to all interest, regardless of when it accumulated. In Order No. 47, we found that the purpose of compounding is to reimburse the customer for the use of the accumulated interest on his overpayments (mimeo, p. 15). Consistentcy requires that we apply this principle to all the interest. Accordingly, clarifying language will be added to our refund regulations consistent with this result.

Order No. 47 made the revised interest rate rule effective as of October 1, 1979. These amendments merely clarify the intent of the regulations adopted in Order No. 47. Therefore, the amendments are hereby made effective as of October 1, 1979.

(Sec. 16, Natural Gas Act, 15 U.S.C. 717o; Section 309, Federal Power Act, 16 U.S.C. 825h; Department of Energy Organization Act, Pub. L. 95-91; E.O. 12009, 42 FR 46267)

In consideration of the foregoing, Parts 35 and 154, of Chapter I, Title 18, of the Code of Federal Regulations are amended as set forth below, effective October 1, 1979.

To the extent not granted in this order, the applications for rehearing are denied.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,100]

44 F. R. 65744 (November 15, 1979)

18 CFR Part 292

[Docket No. RM79-54]

Interim Rule for Qualification of Gas-Fired Cogeneration Facilities for

Purposes of the Incremental Pricing Program; Interim Rule

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Interim rule.

SUMMARY: The Commission gives notice that it has adopted interim rules permitting certain gas-fired cogeneration facilities to be exempt from the incremental pricing provisions of the Natural Gas Policy Act of 1978 (NGPA). The exemption in the NGPA permits cogeneration facilities which qualify under the Commission's rules implementing section 201 of the Public Utility Regulatory Policies Act of 1978 (PURPA) to be exempt from the surcharges for natural gas otherwise provided under the incremental pricing provisions of the NGPA. Under the interim rules, cogeneration facilites which meet certain standards may file an affidavit that they are "qualifying cogeneration facilites," and thereby be exempted from incremental pricing.

EFFECTIVE DATE: November 9, 1979.

FOR FURTHER INFORMATION CONTACT:

Adam Wenner, Executive Assistant to the Associate General Counsel, Federal Energy Regulatory Commission, Room 8104-C, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8171, or

James C. Liles, Office of Regulatory Analysis, Federal Energy Regulatory Commission, Room 3000, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8128.

SUPPLEMENTARY INFORMATION:

November 9, 1979.

Background

On September 28, 1979, the Commission issued final rules implementing the incremental pricing provisions of the Natural Gas Policy Act of 1978 (NGPA).[1] These rules provide, among other things, that natural gas used by "a qualifying cogeneration facility" shall be exempt from the incremental pricing provisions of the NGPA.[2] A qualifying cogeneration facility is defined in the regulations as a cogeneration facility which meets the requirements prescribed by the Commission pursuant to section 201 of the Public Utility Regulatory Policies Act of 1978 (PURPA).[3]

On June 27, 1979, the Commission issued a notice of proposed rulemaking providing requirements for qualification of small power production and cogeneration facilities under section 201 of the PURPA.[4] At this time, the Commission has not promulgated a final rule establishing criteria for qualifying status.

An operative rule setting forth the requirements for a qualifying natural gas-fired cogeneration facility is necessary for the timely implementation of the Commission's incremental pricing program. Section 282.602 of the incremental pricing regulations requires that on or before December 1, 1979, each interstate pipeline must file with the Commission a tariff sheet reflecting a "reduced PGA" rate for the period January 1, 1980, to the effective date of the pipeline's next normally scheduled PGA filing. In order to calculate this reduced PGA rate, each pipeline must ascertain which of the customers it serves, whether directly or indirectly are wholly or partially exempt from being incrementally priced as to their use of natural gas. This information is to be provided by the filing by individual customers of exemption affidavits, a copy of which must be filed with the facility's natural gas supplier. By filing an affidavit, a customer affirms, under penalty of law, that he belongs to one of the several customer groups which is exempt from incremental pricing. In the case of the exemption for qualifying cogeneration facilities, therefore, an industrial customer cannot certify that his facility is a qualifying cogeneration facility until the Commission issues final rules so specifying.

In order to permit natural gas-fired cogeneration industrial end-users to file exemption affidavits in a timely fashion, and thus provide affected pipelines with the information needed to make accurate calculations as to their reduced PGA rates which will be effective January 1, 1980, the Commission finds good cause to issue interim regulations providing that certain existing gas-fired cogeneration facilities can obtain qualifying status on an interim basis, solely for the purpose of obtaining an exemption from incremental pricing.

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[1] Order No. 49, Docket No. RM79-14, issued September 28, 1979.

[2] Sections 282.201(a), and 282.203.

[3] Section 282.202(e).

[4] Docket No. RM79-54, issued June 27, 1979 (44 FR 38872, July 3, 1979.)

The interim qualifying status available to certain existing gas-fired cogeneration facilities will not enable them to obtain any of the benefits set forth pursuant to section 210 of PURPA or to continue to retain the exemption from the incremental pricing of natural gas after final regulations are promulgated in this docket. Those benefits will be available only if a facility qualifies under the Commission's final rules in Docket No. RM79–54. The only benefit to be derived from this interim qualification is exemption from the incremental pricing of natural gas pending promulgation of the final regulations in this docket.

The Commission finds it appropriate to adopt for this interim rule certain provisions proposed in Docket No. RM79–54. In addition, the Commission finds it appropriate to make changes in other proposed provisions of that Docket for the purpose of this interim rule. The adoption of this interim rule in this manner does not reflect a final decision by the Commission as to which gas-fired cogeneration facilities will meet the criteria for qualification under the final rule in this docket. Rather, it indicates that the Commission finds these particular standards and procedures appropriate and expedient for use on an interim basis.

Summary of the Interim Rule

§ 292.501 Scope.

The purpose of the interim rule is limited to establishing an interim exemption from incremental pricing under the Natural Gas Policy Act of 1978.

§ 292.502 Qualifying requirements for cogeneration facilities.

Paragraph (a) provides that, for purposes of Title II of the Natural Gas Policy Act of 1978, a "qualifying cogeneration facility" is a cogeneration facility which was in existence on November 1, 1979, and which used natural gas as a fuel on or prior to that date. In addition, a qualifying cogeneration facility must meet the efficiency standards prescribed in § 292.502 (e) and (f) of this rule.

The fundamental concept behind the provision of benefits to cogeneration facilities is the ability of these facilities to make more efficient use of fuel needed to meet heat and power demands. This more efficient use of fuel is only accomplished when the waste or rejected heat from one power or heating process is used in another heating or power process. Thus, the "combined" or "joint" production of heat and power does not fully define cogeneration; the production must represent the sequential use of the same stream of energy or heat. Such sequential use ordinarily is more energy-efficient than separate production. Section 292.502(a) accordingly requires that a facility must produce electric energy and other forms of useful energy through the *sequential* use of energy.

Section 3 (18)(B)(ii) of the Federal Power Act provides that a qualifying cogeneration facility must be owned by a person "not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration or small power production facilities)." Section 206(c)(2) of the Natural Gas Policy Act of 1978 provides that incremental pricing of gas shall not apply to the generation of electricity by any electric utility. Section 282.203(d) of the Commission's rules implements this exemption. Section 292.206(b) of the Commission's proposed rules in this docket would provide that a cogeneration facility may not qualify under section 201 of PURPA if more than 50 percent of the facility is owned by electric utilities.

The Commission wishes to ensure that cogeneration facilities which satisfy the technical requirements for qualification, but which, because of majority utility ownership, might not be eligible to be qualifying cogeneration facilities under section 201 of PURPA receive the same exemption available for electric utilities referred to above. Accordingly, this interim rule does not contain the ownership limitations set forth in § 292.206(b) of the proposed rules for qualification under section 201 of PURPA.

As a result, qualification under this interim rule is intended both to implement the exemption for qualifying cogeneration facilities in section 206(c)(3) of the NGPA, and to clarify the applicability of the exemption for electric utilities in section 206(c)(2) of the NGPA. Therefore, a cogeneration facility which meets the technical requirements for qualification under PURPA, but which might be excluded because of utility ownership, is nevertheless eligible to be a "qualifying cogeneration facility" for the purpose of exemption from incremental pricing. The Commission emphasizes that qualification of utility-owned facilities under this interim rule does not reflect qualifying status under section 201 of PURPA, or eligibility for the benefits provided under section 210 of PURPA. It is only intended to ensure that the combined effect of the exemptions for qualifying cogeneration facilities and for electric utilities does not exclude efficient cogeneration facilities.

Section 292.502(b) sets forth definitions used to calculate the efficiency of a facility. Subparagraph (1) defines a "cogeneration facility" as the equipment used to produce electric energy and other forms of useful energy (such as heat or steam) used for industrial, commercial, heating or cooling purposes, through the sequential use of energy. Subparagraph (1) limits qualification to equipment used for cogeneration. Therefore, although gas may be used for other purposes at the same location, only gas used for qualifying cogeneration is exempt from incremental pricing.

Subparagraph (2) defines the "useful thermal energy output" of a cogeneration facility as the heat made available for use in an industrial process or for use as space or water heating or cooling.

Subparagraph (3) defines the "useful power output" of a cogeneration facility as the electrical or mechanical energy made available for use, exclusive of any use solely in the power production process.

Subparagraph (4) provides that "total energy input" means the total energy of all forms supplied from external sources to the cogeneration facility. In the case of energy in the form of fossil fuel, the energy input is to be measured by the lower heating value of such fuels.

Subparagraph (5) defines "working fluid energy input" to a cogeneration facility as the enthalpy of steam leaving a boiler minus that of the feed water, when the steam is subsequently used in a topping cycle.

Subparagraph (6) defines "overall energy efficiency" as the ratio of the sum of all useful energy outputs to the total energy input of the facility, measured by means of actual data or estimates. The definition provides that any energy used exclusively in the thermal process of a topping-cycle (supplementary firing) facility shall not be included as energy output or energy input for the purpose of determining the cogeneration facility's overall energy efficiency. The definition of "overall energy efficiency" for this rule is different from that initially proposed in Docket No. RM79–54 in that it is based only on the energy output of the heat and power production equipment, without requiring a computation of process heat utilization efficiency. The Commission makes this change in order to simplify the computation of energy efficiency.

Subparagraph (7) defines "internal energy efficiency" as the ratio of the sum of all useful energy outputs to the working fluid energy input, measured by means of actual data or estimates. This definition also provides that any energy used exclusively in the thermal process of any topping-cycle (supplementary firing) facility shall not be included as energy output or energy input for the purpose of determining the cogeneration facility's internal energy efficiency.

Cogeneration facilities can generally be grouped into two distinct classes: "topping" cycles and "bottoming" cycles. In a topping-cycle cogeneration facility, electricity is generated first and the rejected energy is typically used in a thermal process. Examples of topping-cycles are backpressure steam turbines and combustion turbines with waste heat recovery boilers. Such systems can produce both electric power and process steam. Subparagraph (8) accordingly defines a "topping-cycle cogeneration facility" as a facility in which the energy input is first used to produce power, and the waste heat from power production is then used to provide useful heat.

Bottoming-cycle cogeneration facilities use high-temperature energy for a thermal process first, with subsequent use of the rejected heat for generating electricity. Subparagraph (9) defines a "bottoming-cycle cogeneration facility" as a facility in which the energy input to the system is first applied to a useful heating process, and the residual heat emerging from the process is then used for power production.

Subparagraph (10) states that "supplementary firing" means natural gas used only in the thermal process of a topping cycle, or only in the electric generation process of a bottoming-cycle.

Paragraph (c) sets forth efficiency standards for topping-cycle cogeneration facilities. Only topping-cycle cogeneration facilities are required to meet the efficiency standards set forth in this interim rule. (Complex facilities, with both topping and bottoming generation of electricity or mechanical energy, may be considered bottoming cycles for the purpose of this interim rule). Subparagraph (1) requires that, to qualify, the overall energy efficiency of a cogeneration facility must be no less than 0.55.

An alternative efficiency standard is provided in subparagraph (2) which eliminates boiler efficiency as a standard for qualification. Under this standard, the internal energy efficiency must be not less than 0.70. The alternative efficiency standard is provided to permit qualification of facilities using low-quality fuel burned in association with natural gas, giving rise to low boiler efficiencies.

Paragraph (d) states that a bottoming-cycle cogeneration facility does not have to meet any efficiency standards in order to be a qualifying facility.

Paragraph (e) sets forth the limitation on eligibility for qualification under this interim rule. In order to qualify, a facility must have been in existence on November 1, 1979, and must use natural gas as an energy input. It need not use gas exclusively, but can combine gas with other fuel sources.

Paragraph (f) provides that the Commission may waive any of the standards for qualification, if it finds that such waiver is necessary to encourage congeneration.

Paragraph (g)(1) provides that obtaining qualifying status for purposes of this interim rule does not make a facility eligible for the rates and exemptions set forth in section 210 of PURPA.

Paragraph (g)(2) provides that interim qualification does not necessarily assure that a facility will be a qualifying facility under the Commission's final rules in Docket No. RM79-54, which implement section 201 of PURPA.

Interim qualification will terminate upon the issuance of final rules in Docket No. RM79-54. Facilities qualifying under this interim rule will have to qualify under that rule in order to retain their exemption from incremental pricing.

§ *292.503 Procedures for obtaining qualifying status.*

Section 292.503 provides that an applicant who meets the standards must indicate on the exemption affidavit provided under the incremental pricing program that it is a qualifying cogeneration facility. Upon filing that affidavit with the Commission, with a copy to the supplying pipeline, such facility shall be exempt from incremental pricing.

Section 553(d) of Title 5, United States Code, provides that a substantive rule need not be published 30 days prior to taking effect if the rule grants or recognizes an exemption. As stated above, the regulations below set forth criteria for the determination of an exemption from the Commission's incremental pricing program. Thus, the 30-day period is not required with respect to these rules. The regulations are being made effective immediately, for the reasons stated above.

In consideration of the foregoing, Subchapter K, Chapter I, Title 18, Code of Federal Regulations, is amended by adding a new Part 292 as set forth below, effective on the issuance of these rules.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,101]

44 F. R. 66577 (November 20, 1979)

18 CFR Part 270

[Docket No. RM80-7; Order No. 58]

Final Rule Governing the Maximum Lawful Price for Pipeline, Distributor or Affiliate Production

AGENCY: Federal Energy Regulatory Commission, DoE.

ACTION: Final Regulations.

SUMMARY: On December 1, 1978, the Federal Energy Regulatory Commission (Commission) issued interim regulations (43 FR 56448, December 1, 1978) implementing the Natural Gas Policy Act of 1978 (NGPA). The Commission is issuing § 270.203 of the interim regulations as a final regulation. Section 270.203 defines what sales of production by interstate pipelines, intrastate pipelines, local distribution companies and affiliates of those entities will be considered first sales for purposes of the Natural Gas Policy Act of 1978.

EFFECTIVE DATE: November 14, 1979.

FOR FURTHER INFORMATION CONTACT:

Eli Farrah, Office of the General Counsel, Federal Energy Regulatory Commission, Room 4006-E, 825 North Capitol Street, NE., Washington, D.C. 20426 (202) 357-8316.

Jane Phillips, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8104-B, 825 North Capitol Street, Washington, D.C. 20426 (202) 357-8033.

November 14, 1979.

I. Background

On December 1, 1978, the Federal Energy Regulatory Commission (Commission) issued interim regulations (43 FR 56448, December 1, 1978) implementing the Natural Gas Policy Act of 1978 (NGPA). Section 270. 203(a) of the interim regulations implements section 2(21)(B) of the NGPA and prescribes which sales of natural gas will be considered to be first sales for NGPA purposes because the gas is attributable to production by interstate pipelines, intrastate pipelines, local distribution companies and affiliates thereof. Section 270. 203(b) of the interim regulations defines what other sales by these entities will be considered to first sales in order to prevent circumvention of the maximum lawful prices established under the NGPA. Section 270.203(c) of the interim regulations defines certain terms used in § 270.203.

The Commission has received numerous comments concerning § 270.203 and is amending that section based on an analysis of these comments. Section 270.203 as amended delineates the circumstances under which a sale of production of an interstate or intrastate pipeline, local distribution company (or affiliate of any of these entities) will be regulated as a first sale under the NGPA. Production of interstate pipelines and their affiliates which is not regulated as a first sale under the NGPA is subject to continuing regulation under the Natural Gas Act

(NGA). In response to comments received on § 270.203 and in conjunction with the amendments issued in this order, the Commission is proposing by separate order to add a new § 2.66a to its regulations under the NGA which, in general, will permit interstate pipelines to determine the cost component associated with their own production by reference to NGPA maximum lawful prices, for NGA ratemaking purposes, in those instances where the pipeline would have been allowed the area or national rates under the NGA.

II. Summary of Comments and Revisions to § 270.203

A. *Attribution Rule for Pipelines and Distributors.* Section 2(21)(B) of the NGPA provides that a sale of natural gas by a pipeline, distributor or affiliate thereof is not a first sale unless the sale is "attributable" to volumes of natural gas produced by such pipeline, distributor or affiliate thereof. Section 270.203(a), as amended, describes the circumstances under which a sale of natural gas will be considered to be "first sale" of natural gas "attributable" to volumes produced by a pipeline or distributor. Under the amended rule sales by affiliates of pipelines and distributors are now treated separately in § 270.203(c). Section 270. 203(a) has been clarified to indicate that, to the extent a sale is comprised *exclusively* of production volumes from identifiable wells, properties, or reservoirs which are owned by the pipeline or distributor making the sale, such sale is attributable to volumes of natural gas produced by that pipeline or distributor. For example, if a pipeline were to sell its production at the wellhead, in an offsystem sale, such a sale would generally qualify under § 270.203(a) as a first sale.

As the comments point out, however, sales by pipelines usually do not occur at the wellhead. Pipeline sales generally occur at the point the natural gas is withdrawn from the pipeline's general system supply. Furthermore, pipelines usually commingle the gas they produce with gas purchased from other sources and sell such mixed volumes without regard to the source of the particular volumes of natural gas involved. The Commission is aware that, as a result, most sales by interstate pipelines will not qualify as first sales under § 270.203(a) because the volumes sold are not produced exclusively by and identifiable to the pipeline's own production.

It should be noted, however, that were a pipeline to dedicate natural gas which it produced from an identifiable source to a particular purchaser by contract, commingle the gas with general system supply gas and withdraw equivalent volumes for delivery to that purchaser the sale would generally qualify as a first sale. The sale would qualify because the source of the gas involved is identified and the Commission could be assured that the gas is "attributable" to the pipeline's own production. In addition, the Commission would be able to evaluate requests for allowances for transportation and storage expenses incurred between the wellhead and the point of delivery to the purchaser.

Although many comments have recommended otherwise, the Commission will not interpret the term "attributable" so as to confer first sale treatment on pipeline sales if only a portion of the gas involved was produced by the pipeline. The language of section 2(21)(B) requires that a sale be "attributable" to the pipeline's *own* production. We believe that Congress did not intend for pipeline or distributor sales from general system supply to qualify as "first sales" merely because some portion of that supply, no matter how small, consists of its own production. Rather, we believe that these sales were precisely the type of sales which were intended to qualify for the general exclusion from first sale regulation for pipeline or distributor sales in section 2(21)(B) of the NGPA. The attribution rule accomplishes that result.

Assuming we were to interpret section (2)(21)(B) to treat such mixed volume sales by pipelines or distributors as first sales, the Commission would not adopt such a course because it would result in a wholly inappropriate and unworkable dividing line between "first sales" and other sales, and would override the existing division between Federal and State authority relating to gas sales by pipelines and distributors. The Commission believes that Congress intended that section 2(21) of the NGPA disturb resale rate regulation under the NGA as little as possible. Under the NGA the Commission only has authority to regulate the wholesale rates of interstate pipelines. Retail sales by interstate pipelines, intrastate pipelines and local distribution companies have traditionally been regulated by the States. If the Commission were to treat all pipeline or distributor sales as first sales where any portion of the volume sold is produced by the pipeline or distributor. Commission regulation would extend to retail sales by interstate pipelines to their direct sale industrial customers. The Commission would also be exercising "first sale" jurisdiction over sales by intrastate pipelines and local distributors of volumes produced by these companies. Yet, pipelines and distributors that did not produce any portion of the natural gas involved in their sales would continue to be exempt from first sale regulation under the exclusion in section 2(21)(B) of the NGPA. Moreover, a pipeline or distributor would be able to incur or avoid first sale regulation by entering into production activities or abandoning production activities as it saw fit. The Commission declines to effect such results absent a clearer showing of a need to do so.

Furthermore, if the Commission were to treat all sales as first sales where any portion of the volumes sold is produced by a pipeline or distributor, additional problems would be created in regard to mixed volume sales by pipelines. Where a pipeline makes a sale from general system supply rather than at the wellhead, the source of the particular volumes of gas sold generally cannot be determined. Although comments by pipelines request first sale treatment for such sales they also request allowances for non-production related costs such as transportation and storage which are incurred between the wellhead and the point at which the volumes are delivered to the purchaser and the sale occurs. However, if mixed volume sales by pipelines and distributors were considered to be first sales, the Commission would be unable to reasonably act on such requests for allowances since the source of the particular volumes of gas involved in any given sale could not be determined.

For the reasons stated above, the Commission has decided to limit first sale treatment for pipelines and distributors under the attribution rule to those sales which are statutorily designated as first sales because the volumes sold are exclusively attributable to the pipeline or distributor's production.

Many comments recognize the problems inherent in according first sale treatment to mixed volume sales by pipelines. As an alternative, these comments suggest that the Commission accord first sale treatment to the pipeline's production by imputing a sale at the point where the pipeline takes its gas into its transmission system. However, imputing a sale at the wellhead would extend the first sale concept to intracorporate transactions. As a result, Title I prices would be applied to bookkeeping and accounting entries of a corporation rather than to actual sales. In addition, such a rule would extend NGPA first sale jurisdiction to all corporations which produce their own natural gas. Comments filed by industrial corporations which consume their own natural gas production indicate that this would produce undesirable results and that no valid regulatory purpose would be served by extending the Commission's jurisdiction to cover such production. These comments suggest that such an extension could discourage industrial self-help measures and would contravene the policy expressed in section 608 of PURPA. The Commission agrees that no valid reason presently exists to define intracorporate transfers of gas at the wellhead by intrastate pipelines and distributors as sales. Indeed, to do so would displace existing State regulation of these companies and their production. The Commission declines to effect such results.

B. *Circumvention Rule for Pipelines and Distributors.* Pursuant to its authority under section 2(21)(A)(v) of the NGPA the Commission has defined certain sales by pipelines and distributors, in § 270.203(b), as first sales in order to prevent circumvention of the NGPA maximum lawful prices. Section 270.203(b), as amended, provides that any sale by a pipeline or distributor which is comprised of production volumes from properties owned by the pipeline or distributor and production volumes from other sources will be considered to be a first sale unless one of two exclusions under the rule applies. The first exclusion provides that if the rate at which such natural gas is sold by the pipeline or distributor is regulated under the NGA or is regulated or subject to regulation by a State agency empowered by State statute to establish, modify or set aside the rate for the sale, then the sale will not be considered to be a first sale under the circumvention rule. The second exclusion provides that a sale by a pipeline or distributor will not be considered to be a first sale under the circumvention rule if the Commission, upon application, has determined not to treat the sale as a first sale. The Commission intends to waive first sale treatment under the circumvention rule, pursuant to the second exclusion, only where the applicant has presented sufficient facts to establish that first sale treatment is not needed to prevent circumvention of the NGPA maximum lawful prices. Any application received pursuant to § 270.203(b)(2) will be noticed in the Federal Register, and interested parties will be given an opportunity to comment on the merits of the application.

The circumvention rule for pipelines and distributors is a necessary corollary to the attribution rule. Under the attribution rule, sales by pipelines or distributors are considered to be "attributable" to production by the pipeline or distributor, and thus to be first sales, only where the sale is comprised exclusively of the pipeline or distributor's own production. Mixed volume sales by a pipeline or distributor are not considered to be first sales under the attribution rule. Accordingly, a pipeline or distributor could avoid first sale treatment and circumvent the maximum lawful prices established by the NGPA merely by making mixed volume sales. Section 270.203(b) prevents such circumvention of NGPA prices by regulating mixed volume sales as first sales unless they are subject to other safeguards; *e.g.*, regulation under the NGA, regulation by a State agency, or review by the Commission, on application, in order to determine whether a sale should be treated as a first sale.

Section 270.203(b) avoids the potential for recreating a dual market such as existed under the NGA. By prescribing maximum lawful prices for natural gas without regard to the situs of the sale, Congress sought to eliminate advantages enjoyed by the intrastate market. However, because a sale of mixed volumes would not be "attributable" to a pipeline's own production within the meaning of § 270.203(a), such a sale would not be regulated as a first sale under the NGPA. In those instances where the sale would not be regulated under the NGA or by any particular State, the sale price would not be regulated at all. By continuing to commingle its production with gas purchased from others, the pipeline or distributor could charge prices in excess of those charged by other sellers and could use the increased revenues to pay higher royalties in order to secure additional leases. The pipeline or distributor would have an incentive to make mixed volume sales in a State which did not regulate the price for such sales so that it could secure such an advantage over other producers in securing leases. In order to avoid such a result, § 270.203(b) makes such sales of otherwise unregulated gas first sales unless the Commission, on application, decides that first sale treatment is not necessary in order to prevent circumvention of the NGPA maximum lawful prices.

Some of the comments received by the Commission assert that, while the individual States are given the power in section 602 of the NGPA to set ceiling prices below the NGPA price ceilings, the Commission was only given the authority to create higher ceiling prices and has unlawfully attempted in § 270.203 to establish lower ceiling prices indirectly by precluding application of NGPA maximum lawful prices. These comments have misconstrued the effect of § 270.203. In § 270.203(a) the Commission has interpreted the term "attributable" as that term is used in section 2(21)(B) of the NGPA and has described which sales by pipelines and distributors are attributable to their own production and are, thus, first sales. The Commission believes that its definition of the term "attributable" is the most reasonable and advisable one based on the policies articulated above. The fact that the Commission did not exercise its authority under section 2(21)(A)(v) of the NGPA to subject all pipeline or distributor sales to first sale treatment does not mean that the Commission has set ceiling prices below the NGPA ceiling prices in contravention of section 602 of the NGPA. In fact, in § 270.203 the Commission has exercised its authority under section 2(21)(A)(v) of the NGPA to increase the number of sales which will be governed by the NGPA maximum lawful prices.

C. *Sales by Certain Affiliates of Pipelines or Distributors.* Pursuant to our interpretation of the term "attributable" as it is used in section 2(21)(B) of the NGPA and our authority under section 2(21)(A)(v) of the NGPA, the Commission in § 270.203(c), has provided that any sale by an affiliate of a pipeline or distributor is a first sale if such affiliate is not itself a pipeline or distributor unless the Commission, upon application, has decided not to treat such sale as a first sale. The Commission has also made clear that the term "sale" as it is used in § 270.203(c) does not include any transaction between an interstate pipeline and an affiliate thereof if such transaction would not have been treated as a sale for purposes of the NGA.

The Commission has exercised its authority under section 2(21)(A)(v) of NGPA, in § 270.203(c), to define all such affiliate sales as first sales in order to prevent circumvention of the NGPA maximum lawful prices. The Commission has adopted this approach for the following reason. Sales by affiliates of pipelines and distributors are excluded from first sale treatment by section 2(21)(B) of the NGPA unless such sales are "attributable" to the affiliate's own production. As a result, sales by gatherers who are affiliated with a pipeline or distributor would be excluded from first sale treatment where the gatherer did not produce all of the gas sold, irrespective of whether the gatherer was or was not selling the gas to the affiliated pipeline or distributor. However, sales by gatherers that are *not* affiliated with a pipeline or distributor would not be excluded from first sale treatment. Moreover, an entity selling natural gas could avoid first sale treatment and circumvent the maximum lawful prices established by the NGPA merely by being an affiliate of a pipeline or distributor and conducting transactions which would not otherwise qualify as first sales under § 270.203(a). Accordingly, the Commission has found it necessary to define all sales by affiliates of a pipeline or distributor as first sales if the affiliate is not itself a pipeline or distributor.[1] However, under § 270.203(c) the Commission will entertain applications in individual instances to allow an applicant to present sufficient facts to establish that such first sale treatment is not necessary to prevent circumvention of the NGPA prices.

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[1] See Notice of Proposed Rulemaking issued with this order discussing requirement that an interstate pipeline secure abandonment authorization prior to spinning off production properties to an affiliate.

Treating all affiliate sales as first sales if the affiliate is not itself a pipeline or distributor does no more than recognize what section 2(21) and the other provisions of the NGPA appear to provide for: first sale treatment for all sales which precede sales by pipelines or distributors, where the seller is not a pipeline or distributor. Furthermore, the rule in § 270.203(c) is supported by the desirability of extending Title I maximum lawful prices and related provisions of our regulations concerning resales (§ 270.202) and sales of natural gas subject to differing maximum lawful prices (§ 270.201), and by the need to avoid the anomalous results which would follow from failing to define these sales as first sales.

D. *Reports.* Section 270.203(d), as amended, requires a pipeline or distributor to file a report with this Commission every six months showing the price charged in sales which have been excluded from first sale treatment under § 270.203 (b)(2) and (c). These reports will allow the Commission to re-evaluate those sales in order to determine whether they should be treated as first sales in order to prevent circumvention of the maximum lawful prices established by the NGPA.

E. *Definitions.* Section 270.203(e) defines certain terms as they are used in § 270.203. "Pipeline or distributor" is defined as an interstate pipeline, an intrastate pipeline or a local distribution company. "State Agency" is defined as a State, a political subdivision of a State, or an agency or instrumentality of either.

III. Public Procedures and Effective Date

The regulations in Part 270 were originally proposed for comment in November of 1978 and issued as interim regulations on December 1, 1978 (43 FR 56448, December 1, 1978). For 60 days thereafter comments were received and during that period public hearings were held on these regulations. By this process the Commission complied with the provisions of section 502(b) of the NGPA, which requires that "[t]o the maximum extent practicable," an opportunity for the oral presentation of data, views, and arguments be afforded for certain regulations under the NGPA. The amendments to § 270.203 contained in this order rest upon consideration given to the information received during the above-described notice, comment, and hearing process, as well as upon comments received via the FERC "Hot Line". The Commission finds that further notice and public procedure with respect to these rules is unnecessary. The Commission also finds that good cause exists to make these regulations effective immediately. Delay in the effective date of these regulations, even for a short period of time, may cause pipelines, distributors or their affiliates to postpone, or forego altogether, drilling decisions which would increase the nationwide availability of natural gas. Thus, the Commission is dispensing with the publication requirements of 5 U.S.C. 553(d)(1).

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301 *et seq.*; Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.*; Department of Energy Organization Act, 42 U.S.C. 7107 *et seq.*; E.O. 12009, 42 FR 46267).

In consideration of the foregoing § 270.203 of Part 270, Subchapter H, Chapter I, Title 18, Code of Federal Regulations is issued as a final regulation as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,102]

44 F. R. 66783 (November 21, 1979)

18 CFR Part 271

[Docket No. RM79-73]

Interim Interpretive Regulation; Definition of Term "Produced" as It Relates to Stripper Wells

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Interim Regulation.

SUMMARY: The Commission is issuing an interim regulation defining the term "produced" as it relates to stripper wells under the Natural Gas Policy Act of 1978. The regulation provides that natural gas is produced within the meaning of section 108(b)(3) (A) and (B) of the NGPA (1) on any day during which there is measurable production of natural gas from a well, and (2) on any day during which a well is open to the line but is unable to produce measurable quantities of gas.

The order also provides that days on which a well operator must shut the well in to build up pressure may qualify as "production days" if the jurisdictional agency makes a finding that conservation practice requires such shut-in.

DATES: The regulation is to be effective November 9, 1979. Comments are due on or before January 8, 1980. A public hearing will be held on January 3, 1980. Requests to participate should be received on December 27, 1979.

ADDRESSES: Send comments and requests to participate at the hearing to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. The hearing will be held at the same location.

FOR FURTHER INFORMATION CONTACT: Carol Lane, Office of the General Counsel, Federal Energy Regulatory Commission, Room 4001, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 275-5928 or 357-8511.

November 9, 1979.

I. Background

Section 501(b) of the Natural Gas Policy Act of 1978 (NGPA), 92 Stat. 3350, authorizes the Federal Energy Regulatory Commission (Commission) "to define, by rule, accounting, technical and trade terms" used in the NGPA, so long as such definition is "consistent with the definitions set forth in [the] Act." Pursuant to this authority, the Commission is issuing an interim interpretive regulation defining the term "produced" as it is used in portions of section 108 of the NGPA. We are also clarifying our interpretation of the terms "production day" and "90-day production period."

This order arises out of deliberations held in the course of Commission review of certain jurisdictional agency determinations[1] made under section 108 of the NGPA (stripper well natural gas). These determinations generally fall into three categories, which are described below. Wells in these categories had been preliminarily determined by the Commission not to qualify as stripper wells. In a number of these cases, however, the Commission noted that these Preliminary Findings were tentative conclusions which would be re-examined in a forthcoming rulemaking.

Category A (shut-in wells): This category consists of wells which are manually shut-in due to their inability to meet line pressure. For reasons which will be explained below, the Commission had preliminarily found that days on which a well was shut in for this reason did not qualify as "production days."

Category B (open valve wells): This category consists of wells which are open to the line but are unable to meet line pressure. For reasons which will be explained below, the Commission had preliminarily found that days on which a well was open to the line but not producing gas did not qualify as "production days" and could not make up a "90-day production period."

Wells in categories A and B, are generally low-production gas wells which were in production prior to passage of the NGPA (some for many years). These wells have experienced a drop in pressure to the point where they are incapable of producing against the line without compression or the application of enhanced recovery techniques. Producers of such wells have three alternatives: continued shut-in, abandonment, or installation of enhanced recovery techniques such as compression.

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[1] GP79-46, GP79-48, GP79-50, GP79-65, GP79-70, GP79-84, GP79-103, GP79-106, GP79-63, GP79-76, GP79-120.

Category C (intermittent production wells): This category consists of low-production gas wells which are open to the line and produce natural gas at irregular intervals. In such cases, pressure builds up over a period of time until the well can finally "burp up" a measurable amount of gas. Pressure then drops again and the well produces no gas for another period of time until it can build sufficient pressure once again. This cycle may continue on a regular or irregular basis. The Commission had found preliminarily that days in the cycle on which the well did not produce measurable amounts of gas were not "production days."

The regulation we adopt today changes these preliminary conclusions by defining the term "produced" as it applies to wells in categories (A), (B) and (C), in a manner consistent with what we believe to be the scope and the intent of section 108.

II. Nature of Interim Regulation

The Commission is amending § 271.803 by adding a new paragraph (e) defining the term "produced" as follows:

> Natural gas is produced, within the meaning of section 108(b)(3) (A) and (B) of the NGPA: (1) on any day during which there is measurable production of natural gas from well, and (2) on any day on which a well is open to the line but is unable to produce measurable quantities of gas.

The phrase "open to the line" is intended to describe a situation in which there is no physical impediment to production. For example, a well may have a one-way or back-flow valve which will automatically close when line pressure is greater than well pressure, but there will exist no physical impediment which will prevent the valve from opening again if line pressure drops sufficiently or well pressure increases sufficiently.

The new definition of "produced" is intended to encourage both Renewed production from wells which are presently incapable of producing and continued production from wells which are presently producing on an irregular basis. Once an applicant has the qualifying production date available the installation of a process or equipment which increases the rate of production from the well will be eligible in most cases to qualify as application of a "recognized enhanced recovery technique." [2] If the recognized enhanced recovery technique increases production to a point at which average production exceeds 60 Mcf per production day, section 108(b)(2) provides that the gas may still qualify for the maximum lawful price for stripper well natural gas. [3] Accordingly, the new rule will in many cases make it economically feasible for a producer to perform an enhanced recovery technique on a low-production well.[4] In this way gas which might otherwise be lost will be recovered.

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[2] Section 271.803(a) defines recognized enhanced recovery technique as follows: "Recognized enhanced recovery techniques means processes or equipment, or both, which when performed or installed by the producer, increase the rate of production of gas from a well. Processes qualifying as recognized enhanced recovery techniques include mechanical as well as chemical stimulation of the reservoir formation. Equipment may include items installed in the well bore or on the surface.

"Normal well maintenance, repair, or replacement of equipment of facilities does not qualify as recognized enhanced recovery techniques. Normal completion operations (as defined by the jurisdictional agency or, if the agency has not defined the term, by state custom or practice) which are performed within two years of the initial completion do not qualify as recognized enhanced recovery techniques. Any drilling activity which results in production from another reservoir does not qualify as a recognized enhanced recovery technique."

[3] Section 108(b)(2) states the following: "The Commission shall, by rule, provide that, if nonassociated natural gas produced from a well which previously qualified as a stripper well under paragraph (1) exceeds an average of 60 Mcf per production day during any 90-day production period, such natural gas may continue to qualify as stripper well natural gas if the increase in nonassociated natural gas produced from such well was the result of the application of recognized enhanced recovery techniques."

III. Relevant Provisions of Section 108

The following provisions of section 108 are described in order to demonstrate why wells such as those described above have not, until this time, been considered by the Commission to qualify as stripper wells.

A. *"90-day production period"*: Section 108(b)(1)(A) stipulates that a well's qualification as a stripper well is based on its average production during the preceding "90-day production period." Section 108(b)(3)(B) defines that term as:

> "Any period of 90 consecutive calendar days *excluding any day during which natural gas is not produced for reasons other than voluntary action* of any person with the right to control production of natural gas from such well" (emphasis added).

Under this definition, voluntarily shut-in days may be included in a preceding 90-day production period; therefore shut-in or abandoned wells may experience preceding 90-day production periods even if they have been shut-in for the 180 days [5] prior to the date the application for a stripper well determination is filed. However, wells which were open to the line but experienced no measurable production during the 180 days prior to filing have not been considered to have established a preceding 90-day production period, because involuntarily non-producing days have had to be excluded from any such period.[6]

The regulation we adopt today resolves this problem. "Any day during which natural gas is not produced for reasons other than voluntary action" no longer means any day during which the well was in a production mode (i.e., open to the line) but was unable to produce. Under our new definition, such days are not excluded from the 90-day production period, because they no longer are regarded as non-producing days.

B. *"Production Day"*: Section 108(b)(1)(A) stipulates that in order for a well to qualify as a stripper well, it must have produced nonassociated natural gas at a rate which did not exceed an average of 60 Mcf "per production day" during the preceding 90-day production period. A well's average rate of production is calculated by dividing the total production during the 90-day production period by the number of "production days" in that period. If the figure reached is 60 Mcf or less, the well meets the threshold requirement of section 108. The term "production day" is defined in section 108(b)(3)(A) as:

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[4] It should be noted, of course, that if subsequently the well is determined not to qualify for section 108, any gas produced from the well is subject to the otherwise applicable maximum lawful price.

[5] Section 271.804(c) of the Commission's regulations provides that the 90-day production period upon which the application is based must fall entirely within the 180 days prior to the date the application is filed. See footnote 6.

[6] Section 108(b)(1) provides that stripper well natural gas means nonassociated natural gas produced during any month from a well if during the preceding 90-day production period such well produced at a rate which did not exceed an average of 60 Mcf per production day. Because the statute speaks in terms of *the* preceding 90-day production period, rather than *a* preceding 90-day production period, it appears that Congress did not intend that *any* 90-day production period become the basis for a stripper well determination. Instead, Congress apparently wanted the *most recent* 90-day production period before the date of application to be the basis for the determination. Accordingly, the Commission adopted § 271.804(c), which provides that the 90-day production period upon which the application is based must fall entirely within the 180 days prior to the date the application is filed. This regulation: (1) Resolves time problems caused by the necessity of collecting data from the field by giving producers up to 90 days to file an application with the jurisdictional agency after establishing a 90-day production period; (2) attempts to comply, in as practical a manner as possible, with the intent of Congress that the 90-day production period *nearest* to the application date be the period evaluated by the jurisdictional agency when it makes a determination.

However, in the case of a well which is attempting but unable to produce against line pressure, the producer is not able to establish a 90-day production period within 180 days of the application, because, as explained above, the statutory definition of "90-day production period" excludes involuntarily non-producing days.

(i) Any day during which natural gas is produced; and

(ii) Any day during which natural gas is not produced if production during such day is prohibited by a requirement of State law or a conservation practice recognized or approved by the state agency having regulatory jurisdiction over the production of natural gas.

Read narrowly, this definition precluded as a "production day" any day on which a well was in a production status, i.e., was open to the line, but on which it was unable to produce measurable quantities of gas. When such days were not interpreted to be "production days," there existed no basis upon which to compute the average production "per production day" for a well which remained open but non-producing for an entire 90-day production period. Accordingly, such a well was not considered to qualify as a stripper well.

The rule we adopt today resolves this problem by defining the term "produced" to encompass days on which a well is in a production mode but is unable to produce. Once such days can qualify as "production days," such a well may meet the threshold requirement for a stripper well.

The chart below illustrates how average production per production day may be calculated for a well which is open to the line and produces 100 Mcf of gas every ten days. A typical 90-day production period for this well might be:

	Jan. 15-31	Feb. 1-28	March 1-31	April 1-15	Totals
Calendar days	16	28	31	15	90
Days shut-in for maintenance[1]	0	0	0	5	5
Days of measurable production	2	3	3	2	10
Days open to line with no measurable production	14	25	28	8	75
Total Mcf gas produced	200	300	300	200	1000

Average production per production day for this well is calculated by dividing total production (1000 Mcf) by the number of "production days (10+75, or 85):

$\frac{1000}{85}$ = 11.8 Mcf per production day

Accordingly, the well to which this chart applies would qualify as a stripper well, assuming that it was producing at its maximum efficient rate of flow.

Under our new definition of "produced," we believe that a producer may also find it economically reasonable to reopen to the line a well which is presently shut-in. Even if the well then produces no gas, any open-to-the-line day will qualify as a "production day" and the well will be able to meet the statutory requirements for a stripper well. As noted above, once the qualifying production data is available, the producer is in a position to install enhanced recovery techniques to bring the well into a measurable-production status. If the enhanced recovery technique causes the well's production to exceed an average of 60 Mcf per production day, the producer may retain his right to collect the stripper well price by applying for and receiving a designation that the enhanced recovery technique is "recognized."

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[1] Days on which a well is shut-in for maintenance are not "production days." See pp. 11-12.

IV. Further Clarification of Term "Production Day"

The Commission wishes to clarify two other situations which have caused uncertainty with respect to the term "production day."

The first situation involves wells which are shut-in by the operator intermittently to build up sufficient pressure in the well bore so that the well may produce against the line. The issue is whether such shut-in days may qualify as "production days" for purposes of calculating average production during the 90-day production period. As noted earlier, section 108(b)(3)(A) of the NGPA defines "production day" as:

> (i) any day during which natural gas is produced; and (ii) any day during which natural gas is not produced if production during such day is prohibited by a requirement of State Law or a conservation practice recognized or approved by the state agency having regulatory jurisdiction over the production of natural gas.

Our interpretation of the term "produced," as defined in this order, does not encompass days on which a well is shut-in by the operator. Therefore, part (i) of the statutory definition does not apply to shut-in days. However, we believe that such days may qualify as "production days" under part (ii) of the statutory definition if the jurisdictional agency makes a finding that conservation practice requires intermittent shut-in of the well. Conservation practice signifies, *inter alia,* attempts to prevent waste of natural gas supplies. Ensuring that existing supplies are recovered to the fullest extent possible is such an attempt.

The "conservation practice" finding should verify the particular physical impediment which requires the intermittent shut-in of the well and the number of days the well was shut-in; it should explain the conservation practice which the jurisdictional agency recognizes as applicable in the particular case; and it should explain why the conservation practice as applied to the subject well is necessary to achieve and to maintain production. If such a finding and explanation are provided, the Commission believes it will have substantial evidence that these shut-in days meet the statutory test for "production days."

The second situation arises when the 90-day production period contains days on which the well operator separates the well from the delivery line in order to undertake maintenance or repair. May such days qualify as "production days"? The Commission notes that the number of days on which an operator shuts in a well for purposes of repairs or maintenance is generally within the control of the operator or producer. Such voluntary shut-in days, while clearly included in the 90-day production period (See p. 6), do not meet the statutory definition of "production day." On such days the well was not producing, attempting to produce, or shut-in due to state conservation practice. The well was simply shut-in voluntarily. To permit such days to qualify as "production days" would be to invite manipulation of production in order to qualify for the section 108 incentive price.[8] The Commission notes that the statute was carefully constructed to prevent such manipulation, and we decline to define "production day" in a manner which would circumvent the statutory intent.

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[8] For example, if a well produced 100 Mcf of gas for 54 consecutive calendar days, and then the operator shut the well in for the next 36 days, for "maintenance", there would exist a 90-day production period during which the well produced 5400 Mcf.

Average production per production day for this period would be 5400 divided by 54, or 100 Mcf, meaning the well would exceed the 60-Mcf stripper well limit. But if the "maintenance" days were permitted to qualify as production days, average production would be 5400 divided by 90, or 60 Mcf, meaning the well would qualify as a stripper well.

V. Clarification of Filing Requirements

The Commission recognizes that a jurisdictional agency may not have any means of establishing the number of qualifying "production days" in a given 90-day production period, other than examination of statements filed by the applicant. Section 274.206(a)(5) requires that the applicant file "the number of days natural gas was produced," and § 276.206(a)(6) requires that the applicant file "the number of days natural gas was not produced" and an explanation of the reason for the non-production. In addition to these requirements, we note that each applicant must file:

> A statement * * * under oath, that he has made, or has caused to be made pursuant to his instructions, a diligent search of all records which are reasonably available and contain information relevant to the determination; a description of the search made, the records reviewed, and the results of this search and examination upon which he has consluded that to the best of his information knowledge and belief, the well qualifies as a stripper well; and a statement that he has no knowledge of any other information which is inconsistent with his conclusion;

We believe that this oath statement, in conjunction with the requirements of §§ 274.206(a) (5) and (6), provides a jurisdictional agency with a sufficient basis upon which to determine the number of "production days" in the 90-day production period, absent contradictory information in the record. Where the jurisdictional agency is able to determine the number of "production days" on the basis of information provided on the production period and the statement in § 274.206(a)(6), the requirements of (a)(5) will be deemed satisfied. The jurisdictional agency may, of course, request filing of additional information.

VI. Public Procedure

A. Written Comments

Interested persons are invited to submit comments, data, views, or arguments with respect to this interim regulation. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, and should refer to Docket No. RM79-73. An original and 14 copies should be filed. All comments received prior to 4:30 p.m. EDT, January 8, 1980 will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C., during regular business hours.

B. Pubic Hearings

A public hearing on this proposed rule will be held at the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. on Thursday, Januray 3, 1980, at 10:00 a.m. Any person interested in this proceeding or representing a group or class of persons interested in this proceeding may make a presentation at the hearing provided a written request to participate is received by the Secretary of the Commission prior to 4:30 p.m. on December 27, 1979.

Requests to participate in the hearing should be directed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426. Requests should refer to Docket No. RM79-73 and should indicate that amount of time required for the oral presentation and the telephone number at which the person making the presentation can be reached. Persons participating in the public hearing should, if possible, bring 20 copies of their testimony to the hearing.

The hearings will not be of a judicial or evidentiary type. There will be no cross-examination of persons presenting statements. However, the panel designated by the Chairman may question such persons, and any interested person may submit questions to the presiding officer to be asked of persons making statements. The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. Any further procedural rules will be announced by the presiding officer at the hearings. Transcripts of the hearings will be available in the public file for the proceeding, Docket No. RM79-73 in the Commission's Office of Public Information.

This interim interpretive regulation relieves restrictions previously placed on applicants under the interim regulations. Accordingly, it is being made effective immediately for all determinations which have not become final as of the day before the date of issuance of this order. This regulation shall not become a final regulation, however, until the Commission has had an opportunity to receive oral and written presentation of relevant data, views and arguments.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301, *et seq.*; Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.*; E.O. 12009, 42 FR 46267)

In consideration of the foregoing, Part 271 of Subchapter H, Chapter I, Title 18, Code of Federal Regulations, is amended, as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,103]

44 F. R. 66786 (November 21, 1979)

18 CFR Parts 273 and 275

[Docket No. RM79-66]

Interim Regulation Permitting Withdrawal of Notices of and Applications for Determinations Under the Natural Gas Policy Act

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Interim Regulation.

SUMMARY: The Commission is issuing interim regulations permitting jurisdictional agencies to withdraw notices of determinations regarding certain natural gas qualifying for certain maximum lawful prices under the Natural Gas Policy Act of 1978. The new regulations also permit individual applicants to withdraw applications for determinations which have been transmitted to the Commission.

DATES: The regulation to be effective November 19, 1979; written comments due by January 14, 1980.

ADDRESSES: Written comments to be submitted to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Carol Lane, Office of the General Counsel, Federal Energy Regulatory Commission, Room 4001, 825 North Capitol Street, NE., Washington, D.C 20426, (202) 275-5928 or 357-8511.

November 15, 1979.

I. Background

On August 13, 1979, the Commission issued a Notice of Proposed Rulemaking [1] on amendments to Part 275 of its final regulations under the Natural Gas Policy Act of 1978 (NGPA), 15 U.S.C. 3301 *et seq.* The Notice described the proposed amendments, sought written comments, and announced a public hearing, which was held in Washington, D.C. on September 25, 1979. [2] This order modifies the amendments proposed in the Notice and adopts them as interim regulations.

II. Nature of Amendments

Part 275 of the Commission's regulations establishes the procedures under which the Commission reviews each jurisdictional agency notice of determination that natural gas from a particular well or completion location qualifies for a certain maximum lawful price under the NGPA. Pursuant to the authority granted to the Commission in section 501(a) of the NGPA, we are adopting several amendments to supplement these procedures:

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[1] 44 FR 48282 (August 17, 1979).

[2] *See* Notice of Public Hearings, Docket Nos. RM79-44, RM79-76, and RM79-80, issued September 5, 1979.

(1) *Withdrawals.* Section 275.202(a) of the regulations provides that a jurisdictional agency determination shall become final 45 days after the date on which the Commission receives notice of such determination from the agency, unless during the 45-day period the Commission preliminarily reverses or remands the determination or notifies the agency that the notice is incomplete. The first amendment we adopt in this order provides new procedures under which (a) a jurisdictional agency may withdraw a notice of determination which is before the Commission, and by so doing render that notice a nullity (§ 275.202(c)), and (b) by which an applicant may withdraw an application for a determination which is before the Commission, and by so doing render that application a nullity (§ 275.202(d)).

(2) *Incomplete Notices.* Section 275.202(b)(2) provides that when a notice of determination is found to be incomplete, we will notify the jurisdictional agency within 45 days of the date on which we received the notice. The second amendment we adopt in this order requires the Commission also to notify the purchaser and the parties to the determination proceeding before the jurisdictional agency that the notice is incomplete.

(3) *Conforming Amendment.* Section 273.203(b)(2) is being amended to make a conforming change in a reference in that section to Part 275.

III. Summary of Comments

The Commission received two comments concerning the proposed amendments, one written and one presented at the public hearing. Both comments supported the establishment of procedures for withdrawals but proposed modification of the proposed procedures.[3]

A. Timing of Jurisdictional Agency Withdrawal

The major issue raised by both parties concerned the fact that, under the rule as proposed, a withdrawal could be effected only within the 40-day period following the date on which the notice of determination was filed with the Commission. Both comments suggested that a withdrawal be permitted at any time prior to the date the determination becomes final. In support of this suggestion, one party noted that in many cases the jurisdictional agency may be unaware of any problem with respect to a notice of determination until just before the expiration of the 45-day Commission review period. Accordingly, a 40-day cut-off would preclude utilization of the withdrawal mechanism in the majority of cases. The other party noted that it would be useful to permit withdrawals after issuance of a Preliminary Finding, because at that time the jurisdictional agency would have a better understanding of the deficiencies or errors which the Commission had preliminarily found in the determination. It was argued that a withdrawal at this point would permit appropriate supplementation or correction of the record by the jurisdictional agency before resubmission to the Commission.

We agree that it is reasonable to extend the period during which withdrawals are permitted.[4]

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[3] No comments were received on the proposed amendment to § 275.202(b)(2). Accordingly, that section is being adopted as proposed in the Notice for the reasons specified therein.

[4] The Commission has already granted, by order, at least one withdrawal after issuance of a Preliminary Finding. *See* Order Granting Withdrawal of Jurisdictional Agency Determination, GP79-38, issued October 15, 1979.

Accordingly, the regulations adopted in this order permit a jurisdictional agency to withdraw a notice of determination at any time until it is made final by a final order or by operation of law. There is, however, one problem concerning an extended withdrawal period, which is that the applicant may be unaware of the fact that the determination has not become final but instead has been withdrawn just prior to expiration of the 45-day (or 120-day) period.

It was this type of problem which the Commission sought to avoid when it proposed the 40-day cutoff, allowing a 5-day period for the Commission to give notice before termination of the 45-day period. After due consideration, however, we believe any potential problems of this nature may be overcome not by limiting the withdrawal period but rather by requiring the jurisdictional agency to give notice to the applicant at the same time it notifies the Commission of the withdrawal. This procedure will insure that the applicant will receive timely notice that the status of his well category determination has changed. Accordingly, we are altering the regulation as proposed to condition jurisdictional agency withdrawal upon simultaneous notice to the applicant and to the Commission that the notice of determination has been withdrawn.

B. Effect of Jurisdictional Agency Withdrawal on Interim and Retroactive Collections

Pursuant to § 273.202 of the Commission's regulations, a seller may begin interim collections of the price for which he has applied as soon as he has satisfied the filing requirements of § 273.202(d). Interim collections under this section terminate on the earlier of (1) the date on which the Commission receives a notice of the determination, or (2) 12 months after the first delivery for which interim collection is made (18 months in the case of deliveries beginning before May 1, 1979). (*See* § 273.202(b)(2)).

Accordingly, once the Commission has received notice of determination from the jurisdictional agency, interim collection authority under § 273.202 terminates and any further collection authority depends on the nature of the jurisdictional agency determination. If the determination is negative, the seller may collect only the otherwise applicable maximum lawful price. If the determination is affirmative, the seller may continue to make interim collections of the determined price under § 273.203 until the date the determination becomes final under § 273.203(b). Any such interim collections under § 273.203 cease, however, if a jurisdictional agency withdraws a notice of determination under the withdrawal rule adopted in this order. In the case of a withdrawal under this rule, the applicant would again be entitled to make interim collections under § 273.202, for the following reasons:

(1) *Affirmative Determinations.* When a jurisdictional agency withdraws a notice of an affirmative determination, such determination is rendered a nullity as of the date the Commission, the applicant, and the purchaser are notified. The determination is treated by the Commission as if it had never occurred. Accordingly, upon withdrawal of an affirmative determination, the seller's application is once again pending before the jurisdictional agency and is thus subject to the interim collection provisions of § 273.202 (collection pending jurisdictional agency determination of eligibility). The Commission emphasizes that withdrawal of an initial jurisdictional agency notice by that agency does not terminate the interim collection authority under § 273.202. Accordingly, a seller who is awaiting jurisdictional agency reconsideration of a withdrawn affirmative determination may make interim collections under § 273.202. If the seller has previously filed the required interim collection data under § 273.202(d), he need not file it again.

(2) *Negative Determinations.* The provisions for affirmative determinations described in (1) above also apply to negative determinations.

Accordingly, a seller who is awaiting jurisdictional agency reconsideration of a withdrawn negative determination may make interim collections under § 273.202. If he has previously filed the required interim collection data under § 273.202(d), he need not file it again.

Similarly, jurisdictional agency withdrawal of a notice of determination does not affect a seller's right to make retroactive collections under § 273.204. When a notice is withdrawn and a new notice is submitted to the Commission, the seller is eligible to make retroactive collections of the price which is finally determined to be the maximum lawful price by Commission order or by expiration of the Commission's review period. The seller may collect the difference between the determined maximum lawful price and any lesser price collected after the date the application was filed with the jurisdictional agency.

To summarize what we have explained in detail above, a seller's statutory right to make interim collections remains intact when a jurisdictional agency withdraws a notice of determination from the Commission, and the retroactive collection rules of § 273.204 continue to apply. No comments took issue with this conclusion.

C. Jurisdictional Agency Procedures Regarding Withdrawn Determinations

With respect to the rights of the seller or other parties during a jurisdictional agency's reconsideration of a withdrawn application, the Commission notes that section 503(c)(3) of the NGPA provides that determinations of a Federal or State agency shall be made in accordance with that agency's own procedures. The Statement of Managers of the NGPA states that any party aggrieved by procedural aspects of State or Federal agency determinations may pursue whatever appeal rights are otherwise available under State or Federal law. S. Rep. No. 95-1126, 95th Cong., 2d Sess. 119 (1978). Accordingly, comments concerning determination proceedings for withdrawn applications should be directed to the appropriate jurisdictional agency. No comments took issue with this conclusion.

D. Withdrawal by Applicant

The other suggestion made in one of the comments concerned the fact that the Commission had made no provision for withdrawals by the applicant rather than by the jurisdictional agency. This comment proposed that we permit the applicant to seek withdrawal directly from the Commission, so long as (1) a time limit was set for refiling, or (2) interim collections were cut off during the period the application was withdrawn.

We have adopted the suggestion that an applicant be permitted to seek withdrawal of an application for a determination which has been transmitted to the Commission for review.[5] Regulations governing such withdrawals have been adopted in § 275.202(d). A withdrawal by an applicant may be effected by notifying the Commission, the jurisdictional agency, and the buyer at any time until the determination has been made final by Commission order or by operation of law. Such withdrawal will render the application (and the notice of determination on the application) a nullity. At that point, the applicant's right to make interim collections ceases, and he is required to make appropriate refunds under Part 273 if interim collections of the price applied for have been made.

Because the withdrawn application becomes a nullity, any subsequent application for a determination on the same well is not subject to the provisions of § 273.202(e). Accordingly, interim collections may be made under a subsequent application from the date of filing of such subsequent application. Any retroactive collections made after a final determination on the resubmitted application under § 273.204 may be made only for the period beginning on the date of the subsequent filing. As noted above, the original filing date will be a nullity.[8]

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[5] Procedures governing withdrawal of an application which has not been transmitted to the Commission are, of course, within the jurisdiction of the individual jurisdictional agency.

The Commission recognizes that a jurisdictional agency may not wish a notice of determination which it has submitted to the Commission to be rendered a nullity on the basis of a withdrawal by the applicant. (The agency might prefer that the applicant be required to seek a withdrawal through the agency itself. Then, if the agency agreed to the withdrawal, it would effect it under the provisions of § 275.202(c)). Accordingly, any jurisdictional agency which prefers that its applicants follow a withdrawal procedure other than that adopted in § 275.202(d) should submit an alternative procedure to the Commission during the 60-day comment period described below. Any alternative plan provided by a jurisdictional agency and approved by the Commission for withdrawals by applicants will be incorporated by reference into the final regulations in this docket and will govern the withdrawal of any application filed with that particular agency.

E. Public Procedures and Effective Date

As noted on page 1 of this order, the Commission sought public comment in this docket on the Proposed Regulations regarding withdrawals. We are now adopting those proposed regulations, but with a number of amendments. Accordingly, further comment is sought before promulgation of final regulations.

Interested persons are invited to submit comments, data, views, or arguments with respect to this interim regulation. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, and should refer to Docket No. RM79-66. An original and 14 copies should be filed. All comments received prior to 4:30 p.m. EDT, January 14, 1980, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection in the Commission's Office of Public Information, Room 1000 825 North Capitol Street, NE., Washington, D.C., during regular business hours.

The interim regulations adopted in this order promote administrative efficiency and relieve administrative burdens which would be imposed were the Commission required to review a determination which the jurisdictional agency wishes to reconsider prior to such review. Furthermore, they provide flexibility and avoid unnecessary restrictions upon applicants seeking determinations. Accordingly, we find there exists good cause to make them effective immediately on an interim basis.

(Department of Energy Organization Act, 42 U.S.C. 7107 *et seq.*, E.O. 12009, 42 F.R. 46267; Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3432).

In consideration of the foregoing, Parts 273 and 275 of Subchapter H, Chapter I, Title 18, Code of Federal Regulations, are amended as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,104]

44 F. R. 66789 (November 21, 1979)

18 CFR Part 284

[Docket No. RM79-75]

Certain Sales and Transportation of Natural Gas Policy Act of 1978 and Related Authorities; Order on Rehearing of Order No. 46

AGENCY: Federal Energy Regulatory Commission.

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[8] If an applicant were to withdraw his application from the jurisdictional agency before a notice of determination had been submitted to the Commission the same interim and retroactive collection situation would occur as if he had withdrawn the application from the Commission.

ACTION: Order on Rehearing of Order No. 46.

SUMMARY: The Federal Energy Regulatory Commission (Commission) amended its regulations to provide (1) for pipelines to make requests for interpretation of rate questions from the Commission's Office of General Counsel, and (2) for automatic approval of an intrastate pipeline's proposed transportation rate unless the Commission acts with 150 days of the receipt of the intrastate pipeline's rate application.

EFFECTIVE DATE: Effective December 14, 1979.

ADDRESSES: All filings should reference Docket No. RM79-75 and should be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Robert Platt, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capital Street, N.E., Washington, D.C. 20426 (202) 357-8454.

Federal Energy Regulatory Commission

Issued: November 14, 1979.

On August 30, 1979, the Federal Energy Regulatory Commission (Commission) issued Order No. 46, which contained the final rules implementing sections 311(a) and 312 of the Natural Gas Policy Act of 1978 (NGPA) 15 U.S.C. 3301 *et seq.* Section 311(a)(1) allows the Commission to authorize an interstate pipeline to transport natural gas on behalf of an intrastate pipeline or a local distribution company. Section 311(a)(2) allows the Commission to authorize an intrastate pipeline to transport natural gas on behalf of an interstate pipeline company or a local distribution company served by an interstate pipeline. Section 312 allows the Commission to authorize an intrastate pipeline to assign its surplus natural gas to an interstate pipeline or a local distribution company. Four applications for rehearing of Order No. 46 have been received, from the Railroad Commission of Texas (RR Commission), Texas Gas Transmission Corporation (Texas Gas), East Tennessee Natural Gas Company (East Tennessee) and Delhi Gas Pipeline Corporation (Delhi).

The RR Commission and Delhi object to the definition of "appropriate state regulatory agency." [1] Both are uncertain as to whether the RR Commission falls within the scope of this definition.

In its motion filed September 28, 1979, the RR Commission states that it is required by statute to insure that jurisdictional rates are just and reasonable; that is, the utility shall be able to recover its operating expenses and earn a reasonable return on investment. Since the RR Commission's jurisdiction extends to city-gate service and transportation by intrastate pipelines, it appears that the RR Commission is an "appropriate state regulatory agency" within the meaning of § 284.1(b), at least insofar as it sets city-gate transportation rates. Based on our understanding of the RR Commission's operations, we find that the city-gate natural gas transportation rates set by the RR Commission are derived by applying a costing methodology such that the use of those rates for similar transactions under section 311(a)(2) will satisfy the statutory requirement that the rates are "fair and equitable" and not in excess of "an amount which is reasonably comparable to the rates and charges which interstate pipelines would be permitted to charge." See section 311(a)(2)(B)(i).[2]

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[1] That term was defined in § 284.128 in the interim rules, and in § 284.1(b) in the final rules. There is no substantive difference between the interim and final definitions.

[2] An additional point should be stressed: if a state agency makes no review of the cost of a particular service, the rate for that service would not qualify as being set on a cost-of-service basis. Thus, a state regulatory agency may be "appropriate" within the meaning of the definition for some rates under its jurisdiction, but not for others.

Further, both the RR Commission and Delhi object to the use of the "cost-of-service" standard in the definition on the ground that the phrase is too vague. We will retain the standard, but will clarify its meaning.

The standard is intended to encompass those transportation rates which are set by a state regulatory agency under a methodology which considers the cost of providing the service rather than the price the service can demand. By cost we intend to include operating costs as well as a reasonable return on investment. If there is no rate setting review based upon the cost of providing the service, the rate is not "cost-based", and the agency setting the rate will not qualify under this definition. However, it is not intended that the methodologies utilized by the FERC are the only ones that can be deemed "cost-of-service." Any methodology that involves rate setting based on the cost of providing the service should satisfy the standard.[3]

Besides objection to the "cost-of-service" standard used by the Commission in implementing section 311(a)(2)(B)(i) in § 284.123, Delhi objects to using this approach for purposes of setting the transportation rates for services provided by the intrastate pipeline "in connection" with section 311(b) sales. (Section 311(b) allows the Commission to authorize an intrastate pipeline to sell natural gas to an interstate pipeline or local distribution company. Section 311(b)(2)(B) requires the Commission to set, by rule, a method for computing the compensation due an intrastate pipeline for services rendered in connection with the sale.) Specifically, Delhi contends that the fair and equitable standard under section 311(a)(2)(B)(i) for setting section 311(a)(2) transportation rates differs from the statutory standards for setting the rates for services rendered in connection with section 311(b) sales, and thus the approach of § 284.123 need not be used for section 311(b) sales.

However, the language of section 311(b)(2)(B) is very similar to the language used in section 311(a)(2)(B)(ii). (Section 311(a)(2)(B)(ii) addresses the rates to be charged for services "connected" with the section 311(a)(2) transaction just as section 311(b)(2)(B) governs section 311(b) "connected" service rates). Both used the phrases "reasonably compensate" and "reasonable profit." In promulgating rules under these sections, we determined that it is reasonable to set rates under both sections by reference to the "fair and equitable" standard [4] set forth in § 284.123. We will adhere to that view.

In addressing another aspect of § 284.123, Delhi made an incorrect inference based on Order No. 46's amendment to the language in § 284.123(b)(2). Delhi inferred that by allowing for an affirmative Commission order approving a section 311(a)(2) rate, the Commission has "dramatically shifted * * * the burden of going forward in a rate proceeding. * * *" Such is not the case; the final rule did not place any additional burdens on the intrastate pipeline. The intrastate pipeline which makes a rate filing under § 284.123(b)(2) can begin the transaction prior to Commission review, as it could under the interim rule. It must file "information showing that the proposed rates and charges are fair and equitable," as was required under the interim rule. And, as in the interim rule, the Commission cannot disapprove the rate without "affording notice and opportunity for oral presentation of views, data and arguments." Thus, providing for the specific approval of the rate should work to the advantage of the intrastate pipeline, because such approval would eliminate any uncertainty concerning the possibility that the Commission will later disapprove the rate and order a refund under § 284.2(a).

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[3] City-gate rates to distribution companies tend to be cost-based whether or not they are regulated under a specific tariff. It was with this in mind that the words "city-gate" were inserted in § 284.123(b)(1)(i) (A) and (B). Likewise, the word "comparable" in § 284.123(b)(ii) is intended to refer to city-gate service; a delivery of natural gas directly to an industrial user would not qualify as a "comparable" service.

[4] On page 107 of the Joint Explanatory Statement of the Committee on Conference the term "fair and equitable" is used in describing the total rate to be charged under section 311(b).

However, the Commission has determined that a specific order should not be required to give the necessary rate certainty. Accordingly, § 284.123(b)(2) has been amended to provide that unless the Commission acts [5] within 150 days of the date on which the Commission received notice of the proposed rate, an application filed under § 284.123(b)(2) will be deemed approved.[6] Once the rate is deemed approved, the intrastate pipeline will not be subject to any retroactive refund obligation for failure of the rate charged to comply with the requirements of § 284.123(b)(2). However, the Commission can prospectively revoke its approval (or deemed approval) of the rate at any time.

Delhi also objected to our rejection, on page 4 of the Order No. 46, of the request that "if authorization under section 311(a) is found not to exist the parties to such a transaction be allowed to cease operations without having [Natural Gas Act] jurisdiction attach if the transaction was entered into in good faith."

Our position on this matter will not be changed. The Commission has jurisdiction under the Natural Gas Act over all companies engaged in the transportation or sale of natural gas in interstate commerce unless the company is exempted by some statutory provision. Section 601 of the NGPA grants such an exemption if the transaction is authorized by the Commission under section 311 or 312. However, if the transaction is not authorized under section 311 or 312, section 601 does not apply, and Natural Gas Act jurisdiction attaches. The statutory exemption in section 601 does not mention "good faith." Thus, the Commission has no authority to exempt from Natural Gas Act jurisdiction a party who, through a good faith mistake, engages in a jursidictional activity.

Finally, Delhi objects to § 284.163(b), which limits the price that can be paid under a self-executing section 312 assignment. The limit in both the interim and final rule is the section 102 maximum lawful price for new natural gas. Delhi requests that it be allowed to self-execute assignments priced up to the section 102 ceiling plus state severance taxes. The Commission will maintain this ceiling price for self-executing assignments because we continue to believe that relatively expensive natural gas assignments should receive scrutiny. We have chosen as the appropriate cut-off point for scrutiny the section 102 maximum lawful price. The price set for section 102 gas provides a reasonable point for defining "relatively extensive natural gas assignment" for the purpose of determining which transactions to examine. Moreover, it is administratively useful in a way the suggested figure is not. The section 102 price type of figure is uniform throughout the country and is thus administratively simple to apply in selecting which transaction to examine.

If our future experience in this area indicates a need to set a higher cut-off point for self-executing assignments, we can do so in the future. Under the present rule higher priced assignments can go forward after Commission approval and this approval will be required for transactions which exceed the section 102 price with no additions.

The two other issues raised in the applications for rehearing involve section 311(a)(1) transportation by interstate pipelines. Texas Gas requests that the Commission allow budget-type construction authorization for facilities that must be constructed to effectuate a section 311(a)(1) transaction. The Commission has permitted such authorization with respect to facilities that are jurisdictional under the Natural Gas Act, in its final rules issued on November 1, 1979, in consolidated Docket Nos. RM79-37 and RM79-43.

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[5] The Commission can act by extending the 150 day period, or by instituting a proceeding to examine the rate more fully.

[6] For section 311(a)(2) rates set in accordance with § 284.123(b)(1), as well for any section 311(a)(1) rates, the transporting pipeline may request an interpretation pursuant to § 1.42 of our regulations regarding whether the rate complies with the regulations. Section 284.6 has been included in Subpart A to specifically provide for these interpretations.

Finally, East Tennessee states that the "flowback" rule of § 284.103(d) does not take into account the special circumstances of those interstate pipelines which also perform services which are not subject to the jurisdiction of the Commission under the Natural Gas Act.[7] East Tennessee suggests that the Commission should allow a pipeline with "jurisdictional" and "nonjurisdictional" customers to allocate the revenue between the two, and flow back through Account 191 only the revenues attributable to the jurisdictional customers.

The Commission agrees that such an allocation is proper. The Commission rules require that the interstate pipeline credit only that portion of the revenues (in excess of 1 cent per MMBtu) properly allocable to its jurisdictional customers. The allocation should, as a general matter, be based on the pipeline's ratio of (1) sales for resale subject to regulation under the Natural Gas Act, to (2) total sales, on a monthly basis.

The amendments to the Part 284 regulations which are contained in this Order on Rehearing have been reached after consideration of the comments on these rules received under Docket No. RM79-3, and in consideration of the above referenced applications for rehearing. Accordingly, we find that further notice and public procedure is unnecessary and impracticable and that good cause exists to dispense with additional public procedure and to issue these amendments as final rules.

(Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.*, Natural Gas Policy Act of 1978, 15 U.S.C. 3301 *et seq.*, Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.*, E.O. 12009, 42 FR 46267)

In consideration of the foregoing, Subparts A and C of Part 284 of Subchapter I, Chapter I, Title 18, Code of Federal Regulations, are amended as set forth below, effective 30 days from the date of issuance of this order.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,105]

44 F. R. 67108 (November 23, 1979)

18 CFR Parts 271 and 274

[Docket No. RM79-72]

Clarification of and Amendments to the Regulations and Amendment to the Interim Regulations Implementing the Natural Gas Policy Act of 1978

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rules.

SUMMARY: The Commission is clarifying its final regulations implementing section 103 of the Natural Gas Policy Act, which establishes the maximum lawful price for gas from new, onshore production wells. Also, the Commission is amending the final regulations regarding the well spacing requirements and the special rule applicable to existing proration units. Also, it is amending its interim regulations with regard to requirements for filing with jurisdictional agencies consistent with the amendments to the special rule.

EFFECTIVE DATE: November 16, 1979.

FOR FURTHER INFORMATION CONTACT:

Thom Hirsch, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8511.

Howard Kilchrist, Director of NGPA Compliance, Office of Pipeline & Producer

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[7] Section 284.103(d) requires all but one cent of section 311(a)(1) transportation revenues to be credited to the interstate pipeline's Purchased Gas Adjustment account, Account 191.

Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357–8585.

SUPPLEMENTARY INFORMATION:

Final rule amending regulations on natural gas from new, onshore production wells and amendment to the filing requirements in § 274.204 of the interim regulations; Order No. 43–A Order Granting in Part and Denying in Part Rehearing of Order No. 43 and Amending Regulations (Docket No. RM 79–72) (Issued November 16, 1979).

On August 20, 1979, the Commission in Order No. 43 (44 FR 49651) issued final regulations implementing section 103 of the Natural Gas Policy Act of 1978 (NGPA),[1] which concerns new, onshore production wells. Eight petitions for rehearing of Order No. 43 have been received by the Commission.[2] After consideration of the comments contained in the petitions, the Commission will grant in part rehearing of Order No. 43, amend Subpart C of Part 271 of the final regulations and Subpart B of Part 274 of the interim regulations and clarify certain aspects of Order No. 43.[3]

Special Rule Respecting Existing Proration Units

Each of the rehearing petitions addressed § 271.305 of the final regulations, the special rule applicable to existing proration units. The special rule, as set forth in Order No. 43, provides that in order for a second well on an existing proration unit to qualify as a new, onshore production well, the appropriate jurisdictional agency must explicitly find, prior to drilling, that the second well "is necessary to effectively and efficiently drain a portion of the reservoir covered by the proration unit which cannot be effectively and efficiently drained by any existing well within the proration unit." The special rule also required that, if allowables had been set for the unit by a State regulatory agency, the jurisdictional agency must set separate allowables for both the existing well and the new well.

In Order No. 43, the Commission indicated that a redefined proration unit would be recognized as a proration unit for purposes of section 103 only where the agency, in creating the unit, had made an explicit finding prior to the drilling of a new well that the well was necessary for effective and efficient drainage. In so stating, the Commission made clear that the new well, although it is the first well on a redefined proration unit, would nevertheless be subject to the special rule.

The petitions on rehearing on Order No. 43 raised questions regarding the timing of the effective and efficient drainage finding, the special rule's applicability to redefined proration units, the definition of existing well and the allowables rule. In reconsideration of Order No. 43, the Commission hereby amends its rules regarding the timing of the effective and efficient drainage finding and the definition of existing well for purposes of the special rule. Also, the Commission is modifying its view of the applicability of the special rule to redefined proration units. Finally, the Commission is deleting the allowables rule and is proposing, in a separate rulemaking, to accomplish the objectives of the allowables rule through a more appropriate device.

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[1] 15 U.S.C. § 3301 *et seq.* (1978).

[2] Petitions for rehearing were filed by Sun Gas Company (Sun Gas); Amoco Production Company (Amoco); El Paso Natural Gas Company (El Paso); the State of New Mexico; the Texas Railroad Commission (Texas); Consolidated Oil & Gas, Inc., Four Corners Gas Producers Association an Independent Petroleum Association of New Mexico, jointly, (New Mexico Producers); Indicated Oklahoma Producers (Oklahoma Producers) and the Indicated Producers. The deadline for filing the petitions for rehearing was September 19, 1979. The petition of the New Mexico Producers was stamped by the Office of the Secretary of the Commission on September 20, 1979. The Commission finds that the petition of the New Mexico Producers is untimely filed. However, in light of the importance of the final regulations at issue here, the Commission hereby waives the filing deadline requirement as it applies to the New Mexico Producers.

[3] On October 15, 1979, the Commission received a supplemental filing by Texas, wherein Texas requested that the Commission not apply any additional requirements imposed by Order No. 43 to wells drilled prior to issuance of the order. Texas also requested that the Commission suspend the effectiveness of Order No. 43 in general and hold further conferences to hear and consider additional comments by the jurisdictional agencies on section 103 of the NGPA. The only additional requirement imposed by Order No. 43 was the requirement that in certain situations the agencies must set separate allowables for each well on a proration unit. The requirement has been eliminated, *infra.* We do not find good cause to suspend the final rule, and, accordingly, we will not stay the effectiveness of the rule as modified by this Order.

The Oklahoma Producers and Sun Gas object to the requirement in § 271.305 that the finding regarding the effective and efficient drainage of the proration unit be made prior to the drilling of the new well. The Oklahoma Producers submit that in Oklahoma, appropriate procedures are not available for making the finding prior to drilling. Moreover, these producers submit that even if Oklahoma conducted the necessary proceedings prior to drilling, the proceedings would have no legitimate purpose under Oklahoma law. The Oklahoma Producers contend that in establishing the possibility of alternative procedures in § 271.305(e), the Commission has already recognized that the effective and efficient drainage finding is not required, under the NGPA, prior to drilling. It is requested that the Commission allow the finding to be made as part of the well category determination by the jurisdictional agency, especially where the first well in the unit is no longer producing. Sun Gas adds that this requirement of a prior finding causes substantial delay in the drilling of new wells and thus, in getting new gas supplies to market.

The most obvious shortcoming of requiring the finding prior to the drilling of the new well is a practical one. In many cases, only after the well has been drilled can the appropriate engineering and geological data be collected to make a reasonable determination as to whether the new well is necessary to effectively and efficiently drain the relevant portion of the reservoir. Indeed, in all cases, a more accurate determination can be made after drilling and the collection of more accurate data.

Moreover, the Commission is concerned that by requiring that the effective and efficient drainage finding be made prior to drilling, the drilling of many new, onshore production wells may be unnecessarily delayed. Such delays frustrate the underlying Congressional policy embodied in section 103 of the NGPA to spur the development of new production wells.

The Commission recognizes the difficulty of this issue concerning the timing of the effective and efficient drainage finding. We have therefore re-examined the words of both section 2(8) and section 103 of the NGPA and have determined that the NGPA explicitly directs the nature of the finding which must be made but does not limit the Commission's discretion with regard to what is essentially a procedural decision: the appropriate time for the decision to be made.

Section 103 clearly requires that a well may receive the section 103 price only upon a finding that the well must be necessary to effectively and efficiently drain the reservoir. The Commission does not propose to vary from the statutory requirement that this finding be made. However, the Commission is persuaded by the arguments of the States and the producers that often this finding can be made most appropriately after the well has been drilled.

Arguably, this interpretation is in conflict with a literal reading of the Joint Statement of Managers, which says that "[i]n all cases, the unit must be designated prior to drilling the new well." [4] However, on re-examination of this issue we believe the unintended and detrimental effects of a strict literal application of this admonition can and should be avoided.

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[4] S. Rep. No. 95-1752, 95th Cong., 2d Sess. 81 (1978).

We believe that the purpose of this language in the legislative history is to make clear that the effective and efficient drainage finding must be based on facts concerning conditions as they existed prior to the drilling of the new well, and should not be read literally to preclude a jurisdictional agency from adducing evidence of those facts at a later time, when more complete and informative data is available. This interpretation is particularly compelling in light of policy considerations which favor an interpretation which promotes production, encourages administrative efficiency and avoids anomalous results.

We are of the view that the statutory command can be met, if, on the basis of engineering and geological data (including data obtained after drilling) the jurisdictional agency can reasonably conclude that as of the time of the commencement of surface drilling the specific well was necessary for the effective and efficient drainage of the reservoir. In a case where the only data available to the jurisdictional agency is data obtained after the commencement of surface drilling, the agency may make the effective and efficient drainage finding solely on the basis of that data; the Commission presumes that a finding so supported could have been made at the time drilling commenced, and will regard it as if it had been made at that time.

Section 271.305 will be amended to reflect this change in the Commission's policy and interpretation of section 103, including the deletion of the rule formerly in § 271.305(c) for wells drilled during the transitional period prior to the NGPA. However, it should be noted that where a jurisdictional agency has already made the finding previously required by § 271.305(c), such finding will be accepted by the Commission as satisfying the requirement of the effective and efficient drainage finding under § 271.305(b) for the subject well.

This change in Commission policy regarding the timing of the effective and efficient drainage finding would also alleviate another anomalous result in the case where a producer commences drilling and encounters multiple reservoirs. In such a situation the producer, under our previous requirements, could unexpectedly encounter a reservoir which is not being effectively and efficiently drained by an existing well, but would not be able to collect the section 103 price for gas produced from the reservoir because the appropriate finding did not precede the surface drilling. Our present action avoids such results.

In view of our decision as explained above, the Commission believes that it is similarly appropriate to recognize for the purposes of section 103(c)(2) a waiver or alteration of well-spacing requirements where the waiver or alteration is granted by the jurisdictional agency after drilling of the new well. For example, where the new well penetrates more than one reservoir, the jurisdictional agency might not decide to waive its well-spacing requirements as to a certain reservoir until the agency has found that the well is needed to effectively and efficiently drain that particular reservoir. As noted, especially in the multiple reservoir situation the effective and efficient drainage finding as to some reservoirs is most appropriately made after the well is drilled. Thus, the Commission will no longer require that the alteration or grant of a waiver of well-spacing requirements be made prior to drilling of the new well. Accordingly, § 271.304 is amended to reflect this change.

The next issue raised in the petitions for rehearing concerns the applicability of the special rule where the jurisdictional agency has redefined the boundaries of the existing proration unit designating a new proration unit, prior to the drilling of a new well. Texas submits that § 271.305 should not apply where the new well would have been the second well on a previously existing proration unit, but because of the designation of the new unit is now the first well on the proration unit.

Texas notes that it designates proration units on the basis of the ability of a well (which is to be drilled on the unit) to effectively and efficiently drain the reservoir; thus, Texas argues, the proration unit designation constitutes and implicit effective and efficient drainage finding made prior to the commencement of surface drilling, and should be accepted as such. They conclude, therefore, that the new well, being the only well on the new proration unit designated prior to the commencement of surface drilling, should qualify as a new, onshore production well without the jurisdictional agency being required to make an explicit effective and efficient drainage finding under § 271.305 regarding that well prior to the commencement of drilling. The Indicated Producers make an argument similar to that of Texas.

After reconsidering this matter and reviewing the legislative history of section 103, the Commission now believes that a modification in interpretation of the final regulations is appropriate.

The Commission notes that this issue highlights a possible distinction between the concept of a "State law proration unit" which is used by the States in regulating natural gas production and the concept of "NGPA proration unit" which is defined in the NGPA and the Commission's regulations. A State law proration unit—that is, a proration, production or drilling unit established by a State—is a production area designated on the basis of criteria which may vary from State to State; e.g., correlative rights or State conservation laws. In contrast, an NGPA proration unit is defined in section 2(8) of the NGPA as a portion of a reservoir designated or recognized in a variety of ways as that portion of the reservoir which can be effectively and efficiently drained by a single well.

For the purposes of section 103, the jurisdictional agency can designate or recognize an NGPA proration unit in two ways. First, if the jurisdictional agency *explicitly* finds for purposes of § 271.305 that a second well on a State law proration unit is necessary to effectively and efficiently drain a portion of that unit, for section 103 purposes the agency is making a de facto designation of that portion of the unit as an NGPA proration unit, inasmuch as the State is designating a portion of a reservoir that can be drained effectively and efficiently by a new well. Second, a jurisdictional agency may, prior to drilling a new well, designate an NGPA proration unit by redefining the boundaries of a previously existing State law proration unit, and by establishing the new unit explicitly or implicity on the basis of the effective and efficient drainage of the relevant portion of the reservoir by the new well. In both of these situations, the new well is the only well on the NGPA proration unit and can qualify as a new, onshore production well.

Accordingly, where a jurisdictional agency prior to the drilling of a new well designates a proration unit, either individually or through field rules, on the basis that the designation of the new unit is necessary for effective and efficient drainage, the Commission will recognize a new well drilled in the unit so designated as meeting the requirements of section 103 and will not require the explicit effective and efficient drainage finding under § 271.305 with respect to the new well. If the proration unit is redefined after the drilling of a new well, the state may qualify a new well if it makes an explicit finding. See discussion, *supra*.

The next issue raised in the petitions for rehearing centers on the reference in the special rule to an "existing well" in § 271.305. The question arises because section 103 of the NGPA states that an eligible well may not be within a proration unit which, among other things, applied to a well which produced natural gas in commercial quantities. Under § 271.305, a second well on an existing proration unit may qualify as a new, onshore production well only when the second well is determined to be necessary to drain a portion of a reservoir which cannot be effectively and efficiently drained by "any existing well" located on the proration unit. A problem may arise where State law does not terminate a previously existing proration unit after the last well on the unit is plugged and abandoned; in such circumstances, is the plugged and abandoned well an existing well within the proration unit?

The Oklahoma Producers contend that a well which is incapable of producing, especially one which has been plugged and abandoned, should not be considered an existing well and that in this situation, the new well should not be considered a second well on the unit. The Indicated Producers submit that any well plugged and abandoned prior to January 1, 1970, should not be considered an existing well. These producers assert that it is difficult to ascertain whether a well has been drilled, produced, plugged and abandoned in the distant past, and that the suggested cut-off date is reasonable, because it was used in a similar way by the Congress in defining marker wells in section 2(5) of the NGPA.

The Commission is persuaded by these comments. Accordingly, the Commission will amend § 271.305 to provide that where a well has been plugged and abandoned before January 1, 1970 and has not produced natural gas on or after that date, a rebuttable presumption is created, for the purposes of section 103, that the well has not produced and is not capable of producing natural gas in commercial quantities. Accordingly (unless the record contains information to the contrary) the Commission will accept that a well was plugged and abandoned prior to 1970 as sufficient to meet the requirements in section 103(c)(3)(C) as to the absence of previous production history for the existing well.

The Commission's filing requirements in § 274.204 also will be amended to take into account the use of the rebuttable presumption by the applicant. Of course, the applicant may not use the rebuttable presumption where the applicant has actual knowledge that another well located on the proration unit had produced (or after February 19, 1977, was capable of producing) natural gas in commercial quantities.

The issue that attracted most of the comments in the petitions for rehearing concerned the requirement in § 271.305(b)(2)(ii), that where a State agency establishes allowables or production levels for proration units, the agency must also set allowables for each well in the unit in order for gas from the new well which is the second well in the unit to qualify for the section 103 price. As the Commission stated in Order No. 43 (*mimeo.*, p. 9), it is concerned that where a jurisdictional agency finds that both an existing well and a new well are necessary to effectively and efficiently drain the gas within the proration unit and a State has established allowables for the unit but has not established separate allowables for each well, there is an incentive to produce a disproportionate amount of gas from the new well because it commands the higher section 103 price. To prevent this, the Commission in § 271.305(b)(2)(ii) conditioned eligibility on the jurisdictional agency setting separate allowables for each well, based on the respective ability of the well to deliver gas.

Texas, the State of New Mexico and the New Mexico Producers have raised various procedural and substantive objections to the allowables rule. They submit that the rule represents an unlawful intrusion into the preserve of State regulation, is discriminatory in effect and is unduly burdensome to both producers and jurisdictional agencies. They also urge that interested and affected persons be afforded notice and an opportunity for comment on this regulation prior to its effective date.

In consideration of these comments, the Commission believes that the objective of the allowables rule—to assure that a disproportionate amount of the gas which can be produced from the unit is not priced at the section 103 price—can be better accomplished by other means, and has decided that further comment by interested and affected parties would be advantageous. Therefore, the Commission is deleting the allowables rule and will issue in connection with this order a notice of proposed rulemaking which will address the concerns previously addressed by § 271.305(b)(2)(ii) under circumstances in which the jurisdictional agency does not establish allowables on a well-by-well basis.

The Oklahoma Producers request that the Commission clarify when the jurisdictional agency must notify the Commission under § 271.305(c) (formerly § 271.305(d)) that the agency has made an effective and efficient drainage finding. The Commission advises that only where the finding relates to a well that later becomes the subject of a section 103 determination and only when that determination is forwarded by the agency to the Commission must the agency so notify the Commission.

The New Mexico Producers request that the filing requirements contained in § 274.204 concerning new, onshore production wells be clarified to apply also to infill wells approved on a poolwide basis. This issue is currently before the Commission in a proceeding involving the alternative filing plan of the State of New Mexico, and will be resolved in that proceeding. See Docket No. RM79-3.

Because the amendments to Subpart C of Part 271 and Subpart B of Part 274 issued herein relieve restrictions previously imposed by the final rule issued in Order No. 43, and the interim regulations regarding filing requirements, the Commission is issuing these amendments effective immediately with regard to jurisdictional agency determinations which have not yet become final under § 275.202 as of the day before the date of issuance of this order. 5 U.S.C. 553(d)(1).

Therefore, in considering all future and pending applications, the jurisdictional agencies may make the effective and efficient drainage finding before or after drilling. Of course, the Commission would uphold a jurisdictional agency determination based on a finding made prior to drilling, in compliance with the prior rule of § 271.305 that a well qualifies as a new, onshore production well, so long as the determination is otherwise in compliance with applicable Commission regulations.

If a jurisdictional agency found prior to the effective date of these amendments that a well qualifies as a new, onshore production well based on an effective and efficient drainage finding made after drilling, the producer may take advantage of the change in § 271.305; that jurisdictional agency determination, if it is otherwise in compliance with applicable Commission regulations, will also be upheld. The Commission knows of no case pending before us for review in which a jurisdictional agency, in compliance with the prior rule of § 271.305, has found that the well is ineligible to qualify under section 103 because no effective and efficient drainage finding had been made prior to drilling. If such a case should arise, however, the Commission would reverse the agency determination where evidence in the record supports a finding made either before or after drilling that the well is necessary to effectively and efficiently drain the reservoir. In the absence of such evidence, the Commission would permit the jurisdictional agency to supplement the record by providing additional evidence, adduced after drilling, that the well is necessary to effectively and efficiently drain the reservoir.

In the case of an adverse section 103 determination which has become final under § 275.202, the applicant may seek an adjustment under section 502(c) of the NGPA, if the applicant believes that the change regarding the timing of the effective and efficient drainage finding has caused a special hardship, inequity or unfair distribution of burdens. The Commission will consider such adjustments on a case-by-case basis, consistent with the provisions of § 1.41 of the Commission's regulations.

Similarly, in the case of future applications and all applications pending before the jurisdictional agency or the Commission, an applicant may take advantage of all other amendments to the Commission's regulations set forth in this order (including deletion of the allowables rule), and the change in the Commission's interpretation of its regulations with regard to the redefinition of the bundaries of proration units. To the extent necessary, the Commission would handle such cases in a manner similar to the manner in which it intends to handle the amendment regarding the effective and efficient drainage finding. In addition, if an adverse section 103 determination has become final under § 275.202, an applicant who believes that he has suffered a special hardship, inequity or unfair distribution of burdens because of that determination, may seek an adjustment under section 502(c) of the NGPA and § 1.41 of the Commission's regulations.

The Commission Orders: (A) To the extent not granted above, the applications for rehearing of Order No. 43 are denied;

(B) Order No. 43 is clarified, as set forth above; and

(C) Sections 274.204 of the Commission's interim regulations and §§ 271.304 and 271.305 of the final regulations are amended and made effective as set forth above.

(Natural Gas Act, as amended, 15 U.S.C. § 717 *et seq.*; Department of Energy Organization Act, 42 U.S.C. § 7107, *et seq.*; Exec. Order No. 12009, 42 Fed. Reg. 46267; Natural Gas Policy Act of 1978, 15 U.S.C. § 3301, *et seq.*)

In consideration of the foregoing, Subpart C of Part 271 and Subpart B of Part 274, Subchapter H, Chapter I, Title 18, Code of Federal Regulations are amended as set forth below, effective immediately with regard to jurisdictional agency determinations which have not yet become final under § 275.202 as of the day before date of issuance of this order.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,106]

44 F. R. 67644 (November 27, 1979);
44 F. R. 75383 (December 20, 1979).

18 CFR Parts 2, 4, 16

[Docket No. RM79-36; Order No. 59]

Regulations Governing Applications for License for Major Projects—Existing Dams

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) revises its regulations under Part I of the Federal Power Act that govern applications for licenses for major water power projects located at existing dams. Major projects are those with an installed capacity greater than 2000 horsepower or 1.5 MW. Such projects are governed by this rule if they utilize, or are proposed to utilize, the water power potential of a completely constructed dam, provided that the normal maximum surface area or elevation of the impoundment would not significantly change or that a significant environmental impact would not otherwise result. The final rule applies both to initial licenses and new licenses.

Under section 405 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.C. 2705, the Commission is charged with establishing simplified and expeditious licensing procedures for "small" hydroelectric projects (15 MW or less) at existing dams. The Commission has decided to reform all its licensing procedures in the interest of acting more promptly on applications. This rulemaking covers all the projects within the mandate of section 405 of PURPA, except for hydroelectric projects under 1.5 MW of capacity. Applicants for these "minor" projects are permitted the use of "short-form" license procedures.

The final rule reorganizes the license application requirements for major projects—existing dams and consolidates the provisions and exhibits into two sections. The Environmental Report required by the National Environmental Policy Act of 1969, together with related consultation and reporting requirements under other environmental and preservation statutes, is presented in Exhibit E, rather than in five separate exhibits and portions of Part 2 under the existing regulations.

The overall effect of the new regulations will be to reduce the amount of information requested from applicants, to make the regulations clearer and better organized, and thereby to ease the burdens of compliance and improve the Commission processing of applications.

EFFECTIVE DATE: January 1, 1980.

FOR FURTHER INFORMATION CONTACT:

James Stout, Director, Division of Licensed Projects, Office of Electric Power Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, 202-275-4866.

Howard Jack, Assistant General Counsel, Hydroelectric Licensing, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, 202-357-8446.

or

James Hoecker, Commission Staff Counsel, Regulatory Development, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, 202-357-8033.

November 19, 1979.

Notice is hereby given that the Federal Energy Regulatory Commission (Commission) revises its regulations concerning applications for licenses for water power projects under Part I of the Federal Power Act (Act). The new regulations pertain to applications for licenses for major projects (capacity greater than 2000 horsepower, or 1.5 MW) which utilize, or would utilize, the water power potential of existing dams only. The regulations govern applications which seek: (1) An initial license [1] for an existing water power project with total installed and proposed capacity greater than 2000 horsepower, or 1.5 MW; (2) a new license [2] for an existing water power project with total installed and proposed capacity greater than 1.5 MW; or (3) an initial license for a proposed water power project at an existing dam or dams, with proposed capacity greater than 1.5 MW. The projects in these categories are referred to generically as "major projects—existing dams."

I. Background

Congress provided in Title IV of the Public Utility Regulatory Policies Act (PURPA), a component of the National Energy Act, a program whereby the Secretary of Energy will grant loans for feasibility studies and for construction of "small" hydroelectric projects (capacity of 1.5 MW or less) located at existing dams. The Commission is charged under section 405 of PURPA, 16 U.S.C. 2705, with establishing simple licensing procedures for projects eligible under the PURPA provisions.

In the interest of acting more promptly on all license applications, and in anticipation of the enactment of PURPA, the Commission determined in 1978 to reform its requirements and procedures for all license applications. The first phase of this reform was instituted in September 1978, with issuance of a rulemaking on the "short-form" license procedures applicable to all minor projects (capacity of 1.5 MW or less).[3] On April 19, 1979, the Commission continued its licensing reforms by issuing a Notice of Proposed Rulemaking in this docket (44 FR 24095, April 24, 1979).

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[1] "Initial license" is defined as the first license issued for a water power project under either the Federal Water Power Act of 1920 or the Federal Power Act.

[2] "New license" is defined as any license for a water power project that is issued under the Federal Power Act after the initial license for that project, except an annual license issued under section 15(a) of that Act, 16 U.S.C. 808(a).

[3] Order No. 11, Docket No. RM78-9, 43 FR 40215 (September 11, 1978). The 1.5 MW (2000

The Commission also has issued final regulations that prescribe general filing requirements and evaluation procedures applicable to both preliminary permit and license applications, and which simplify the regulations relating specifically to applications for preliminary permits, amendments to permits, and cancellation of permits.[4] The regulations in this order subsume the remainder of the projects which fit the criteria of the PURPA provisions and which were not embraced by the "short-form" license procedures. Since the equities which warrant streamlined requirements and procedures for proposed water power projects at existing dams are applicable to existing water power projects as well, the scope of this rulemaking has been made as inclusive as possible in order to maximize its benefits.

The existing requirements for the types of license applications which fall within the scope of this rulemaking are found in various parts of Title 18 of the Code of Federal Regulations. Substantive requirements applicable to one or all of these applications may be found in §§ 2.80 and 2.81, Appendix A to Part 2,[5] §§ 4.40–4.51, 16.6, and 131.2 of Title 18. In following those regulations, a potential applicant faced the prospect of meeting information requirements embodied in at least 12 itemized paragraphs and up to 23 exhibits.

The new regulations set forth in this order in several ways ease the burden of compliance. First, the Commission has reduced the requested information to the minimum that is needed for the Commission to carry out its duties under existing law[6] in an informed and responsible manner. For example, among other unnecessary requests for information, the provisions requiring extensive documentation of the nature of the applicant and its authority to file the application, have been eliminated,[7] and requirements relating to evidence of compliance with state laws simplified. Of course, this in no way relieves the obligation to comply with any state law not preempted by Part I of the Act.

Second, the Commission has consolidated the requests for information according to related subject matter. All paragraphs and exhibits requesting information on environmental matters,[8] for instance, have been consolidated into Exhibit E (Environmental Report) required under § 4.51(f). Rational organization of the

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horsepower) capacity criterion was based on the fact that the Commission is authorized under section 10(i) of the Act, 16 U.S.C. 803(i) to waive many of the requirements of Part I of the Act for such minor projects. Since the capacity limitation prescribed in PURPA is 1.5 MW, the first phase of the reform covered only a portion of the projects that would be eligible under the PURPA program.

[4] Final regulations in Docket No. RM79–23 were issued by the Commission on October 22, 1979 (44 FR 61328, October 25, 1979). The regulations in this rulemaking refer to, and may be read in conjunction with, the regulations in Docket No. RM79–23.

[5] Sections 2.80 and 2.81, constituting most of the Commission's existing environmental review regulations, would be revoked and replaced under the rulemaking implementing the National Environmental Policy Act of 1969 (NEPA) in Docket No. RM79–69 which has been proposed to render the Commission's regulations consistent with the guidelines of the Council on Environmental Quality Appendix A would be amended and transferred to new Part 3d under the same rulemaking. 44 FR 50052, August 27, 1979.

[6] Section 405 of PURPA provides that the Commission's simplified licensing procedures must be "consistent with the applicable provisions of law," and that no project covered by the procedures will be exempted from "any requirement applicable to any such project under the National Environmental Policy Act of 1969, the Fish and Wildlife Coordination Act, the Endangered Species Act, or any other provision of Federal law."

[7] See existing §§ 4.40(b) and 4.41—Exhibits A–F. These requirements have been distilled to simple statements in the initial portion of the application under § 4.51(a). Since the entire application is subscribed and verified under § 1.16 of our rules, the statements themselves will suffice as evidence. Additional information will be requested in cases where it is needed.

[8] See existing § 2.80, Appendix A to Part 2, § 4.40 (k) and (l), and § 4.41—Exhibits H, R, S, V, and W.

requirements should reduce confusion and redundance in the materials submitted.

Finally, the regulation minimizes the element of subjective interpretation in our requirements by reducing the requests for information, where possible, to simple, objective descriptions of what is desired. The Commission believes that clearer, simpler requirements and a cooperative effort will help avoid the application deficiencies that have plagued the licensing program in the past.

II. Analysis of Comments

Most commenters expressed overall approval of the Commission's efforts to simplify licensing requirements pursuant to section 405 of PURPA. However, there were a variety of comments declaring that the Commission's proposed license application requirements are still too burdensome, and others arguing that more information should be required.

This analysis will first examine the volume of comments which focused on environmental and other reporting requirements. Particular concern was expressed with respect to the amount of information requested about projects at existing dams where the environmental consequences of a project are presumed normally to be minimal. Allegheny Power Service Corporation (APS) stated that Exhibit E is the equivalent of a full Environmental Impact Statement and is too lengthy and subject to interpretation as proposed.[9] The cost of preparing the exhibit will inhibit development of small projects, according to APS. Therefore, a mere statement of a project's impact should suffice. The American Electric Power Service Corporation (AEP) likewise stated that adherence to all the specifications in Exhibit E may not be feasible in all cases, pointing specifically to requirements that all communications with other agencies consulted be submitted, that the applicant specify what measures the agencies recommended, and how the applicant plans to implement those recommendations or why it does not plan to comply.

In the Notice of Proposed Rulemaking, the Commission recognized that, since most significant impacts associated with projects at existing dams have already occurred, a less extensive environmental analysis is appropriate.

The licensing reforms proposed in this docket and those issued in Docket No. RM79-23 (*see* footnote 4) were drafted with the idea that an applicant's submittals to the Commission should always be commensurate with the scope of the particular project. The environmental report in Exhibit E will cover the temporary and permanent impacts of new construction, as well as the continuing impacts of operation of the proposed project; it would not include the impacts that occurred during construction of the existing dam. Much of the information required by the Exhibit should be readily available. The nature of the project determines the extent of the information necessary for an acceptable application. If the applicant's own analyses, in light of consultation with state or Federal agencies, indicate that the effect on resources within their jurisdiction (*e.g.*, historical and archaeological resources or water quality) would be minimal, the report to the Commission would likewise be minimal. It is nevertheless important that each application be sufficiently self-explanatory regarding the existing state of the project works in order to enable the Commission to evaluate the existing and prospective impacts of the project works on such things as water quality and to understand the design of all related portions of the project. Moreover, the Commission also needs the information required in Exhibit E to fulfill its responsibilities under the Fish and Wildlife Coordination Act, the

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[9] Exhibit E is an Environmental Report (ER) required of applicants under the Commission's NEPA processes. (§ 3d.12(c)(1)(ii)) Under the proposed revision of those processes [see footnote 5], an ER must meet much less stringent standards than an EIS.

Endangered Species Act, the National Historic Preservation Act and other Federal laws—all expressly saved in section 405(b) of PURPA—as well as its mandate under the comprehensive development standard in section 10(a) of the Act.

Southern California Edison Company (SCE) suggests that the reports on consultations with various resource agencies (§ 4.51(f)(5)) should not require accompanying documentation in the form of all written communications, but only "final agreements" with the agencies. Other commenters questioned the need for including all communications. The Commission desires only that pre-application consultation be complete and verifiable. The Commission nevertheless agrees with SCE that copies of all communications would make Exhibit E unnecessarily cumbersome. The language of § 4.51(f)(5) is therefore amended from that which was proposed to require the applicant to submit letters from the resource agencies consulted showing the nature and extent of the consultations.[10] In accordance with the suggestion of the Power Authority of the State of New York (PASNY), § 4.51(f) has also been altered to state explicitly that the informational requirement related to agency recommendations applies only to "agencies consulted." This makes it clearer that the responsibility to report extends only to consultation with agencies that have jurisdiction over particular resources.

Montana Power Company (MPA) asserts that § 4.51(f)(6)(iii), which requires analysis of cost and constraints involved in providing a buffer zone around any impoundment for public access and protection of recreational resource values, virtually requires an applicant to prove that it cannot provide a buffer around an impoundment. It is claimed that a buffer zone is not appropriate in sparsely populated areas such as Montana.

The buffer zone requirement is not new. It was established by the Commission in Order No. 313,[11] pursuant to the Commission's responsibilities under section 10(a) of the Act and the policy on outdoor recreation and resources declared in Pub. L. 88-29.[12] Order No. 313 states that applicants are expected to provide such buffer zones within the project boundary. Whether there are factors that make such buffer zones uneconomical or unneeded for a particular project must be determined on the basis of the information submitted by the applicant. The new regulation does not change the policy of Order No. 313, but simply requires that the matter be addressed at the outset in a licensing proceeding in preparation of the application. No new burden of proof is thereby imposed on applicants.

Idaho Power Company (IPC) and Pacific Gas and Electric Company (PG&E) inquire whether a buffer zone is within the project boundary. Section 2.7(a) of the Commission's regulations makes clear that it is. Finally, PG&E suggests that § 4.51(f)(6)(iii) should pertain only to "reasonable" public access. The standard articles which accompany issuance of a project license[13] condition approval of the project on provision of public access to a reasonable extent and consistent with the protection of life, health, and property. Such conditions need not be specified in the application regulations.

PG&E believes that the Report on Land Management and Aesthetics (§ 4.51(f)(6)) expands the reporting requirements in existing Exhibit V. In fact, as other commenters recognized, the information required in that report and other portions of Exhibit E is substantially less than what is required under the existing regulations. Existing Exhibits V and W require far more information and analysis on land use and aesthetics than this rule. In some respects, the new regulation is more specific in its data requests, in order that delays resulting from deficient applications or requests for additional information may be avoided. But the overall level of information and analysis is substantially reduced. The same observation is appropriate with respect to the comment of MPC that the new regulation, as a whole, represents an expansion of reporting requirements for applicants.

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[10] Although consultation is required at an early stage, while an applicant's plans are still being shaped, an agency may not use consultation as a device to obstruct a project. The prefatory paragraph of Exhibit E (§ 4.51(f)) has been amended by providing that an applicant may submit its own summary of the consultations, but only if the agency fails to supply such documentation in timely fashion. The Commission believes that this should allay the fears of companies such as Niagara Mohawk Power Corporation that undue delays in the agency consultation process might arrest progress on a project.

[11] 30 FR 16198, December 22, 1965, 34 F.P.C. 1546 (1965).

[12] Section 1, Outdoor Recreation Programs, Act of May 28, 1963, 16 U.S.C. 460.

[13] Form L-1, Articles 17 and 18, Order No. 540, 40 FR 51998, November 7, 1975.

The Commission received several comments of an environmental nature from the U.S. Environmental Protection Agency (EPA). While EPA acknowledges that the impact of projects at existing dams would be less than those involving construction of dams and reservoirs, it also appears to believe that the regulations might not adequately assure assessment of the lesser impact of projects at existing dams, particularly "peak load production projects which cause major fluctuations in the impoundment level and downstream flow." The Commission believes that Exhibit B and Exhibit F, specifically the reports on water use and quality, recreation resources, and fish, wildlife and botanical resources, will provide sufficient information to assess impacts of those kinds.[14] Exhibit B (§ 4.51(c)) has, however, been clarified in response to the suggestions of EPA and other commenters, to require information on "minimum, mean, and maximum recorded flows" (§ 4.51(c)(2)(i)) and on project operation during "adverse, mean, and high water years" (§ 4.51(c)(1)).

EPA further requests that an applicant show how it will ensure stream flows sufficient for maintenance of approved water quality standards and wastewater treatment facilities. Section 4.51(f)(2), the "report on water use and quality," will provide information in conjunction with Exhibit B sufficient to assess the project's water quality implications. EPA also proposes additional language for § 4.51(f)(2)(iv) concerning evidence of water quality certification or state waiver. We believe that section is sufficiently clear and detailed and that the changes proposed by EPA therefore need not be made.

Certain changes have been made at the suggestion of EPA, however. Language requesting identification of applicable water quality standards and stream segment classifications is added to Exhibit E (§ 4.51(f)(2)(ii)). The final rule makes reference, where appropriate, to the "Clean Water Act," as the familiar designation for the Federal Water Pollution Control Act. Finally, a cross-reference to EPA guidelines and Army Corps of Engineers regulations relating to dredging and filling is also added to Exhibit E (§ 4.51(f)(2)(iii)).

The U.S. Department of Agriculture requested that the Commission obtain from the Fish and Wildlife Service a list of endangered species in the area of proposed projects and that this be specified in § 4.51(f)(3)(i). One purpose of the consultation process on natural resources provided by this section is to ensure that the applicant obtain such information from the relevant agencies and supply it to the Commission in its Environmental Report. In any event, the Commission believes it is not necessary to specify in its regulations on application requirements that it will comply with procedures required by section 7 of the Endangered Species Act in acting on applications.

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[14] The regulations recognize that changes in project works which do not raise normal impoundment areas or levels may still have a significant impact. If a peak load production project entails a major change in project operations resulting in a significant impact, it would not be within the scope of the definition of a major project—existing dam as defined in § 4.50(b)(5) and therefore these regulations would not govern that project. Also see proposed § 3d.10(b)(7) in Docket No. RM79-69, cited in footnote 5.

The U.S. Department of the Interior (DOI) submitted several comments relating to the Environmental Report requirements under Exhibit E. At the suggestion of DOI, § 4.51(f)(5) is amended to include a description of any area within or near the project boundary that is designated as part of, or is being considered for inclusion in, the National Wild and Scenic Rivers System or the National Wilderness Preservation System. Related proposals that the new regulations include a description of trade-offs between conservation and other project objectives involve issues and conclusions to be developed in the course of environmental evaluations under the Commission's NEPA regulations. The information already required in Exhibit E will be sufficient for the data-gathering purposes of these regulations. Assessment of habitat losses and methods of compensation losses are encompassed in the final rule.

Under proposed § 4.51(f)(2)(v), an applicant would have had to provide a description of the "new impact" on water quality caused by project operations. Niagara Mohawk Power Corporation (NMP) believes "new impact" to be too imprecise and that an indication of "incremental" impact would be preferable. The clause has been revised to require a showing of the continuing impact of project operations on water quality, as well as the incremental impact that would occur as a result of new development or changes in project operation. Similar changes have been made in other relevant portions of Exhibit E.

Harza Engineering Company (Harza) and PG&E appeared to find § 2.81(a) unclear. Harza advocates that we broaden application of this regulation to include proposed dams. While § 2.81, as the predecessor to the Commission's revised NEPA regulations (*see* footnote 5), applies to different types of water power projects, the Commission is concerned in this docket only with revising environmental reporting for projects at existing dams. Revised rules on applications for major unconstructed projects are being developed and will be forthcoming.

PG&E requests clarification of what is meant by a project that would result in a "significant increase in normal surface area or normal surface elevation of an existing impoundment." As § 2.81(a) implies, projects with such consequences would not be considered projects at "existing dams" for the purpose of this licensing regulation. The issue of whether such area or surface elevation increases are significant resists the imposition of specific criteria. The significance of the increased area or surface elevation of an impoundment will depend on the surrounding topography and land uses. For example, a relatively small increase in impoundment elevation near flat land may have dramatic consequences for the surface area and consequently for the surrounding land uses or ecosystems. The effect of the project may therefore necessitate the filing of an application conforming to the more stringent requirements for a major unconstructed project (*see* the definition of major project—existing dam, § 4.50(b)(5)).[15] For this reason, applicants are encouraged to consult with staff under § 4.50(c) to determine the probable significance of any new development at an existing dam site and thereby ascertain the proper application type at the outset.

The City of Colorado Springs Department of Utilities (CSDU) suggests that facilities operated primarily as a water supply system, even if related to generation and transmission facilities.

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[15] Similarly, the importance of site-specific conditions leads the Commission to reject suggestions of EPA and other commenters that we establish an *a priori* definition of "significant environmental impact."

should be exempted from licensing requirements. The Commission is authorized to make such exemptions only for certain small conduit hydroelectric facilities under section 213 of PURPA (section 30 of the Act) and has proposed a rulemaking to accomplish this.[16] Such exemptions are beyond the scope of this rulemaking. With respect to the comment of CSDU that less detailed reporting requirements are appropriate for the relicensing of existing facilities, the Commission is adapting this and related water power project rulemakings to obtain less specific information for existing dams and reservoirs and more extensive technical data for unconstructed projects. Nevertheless, there are important environmental, structural and other considerations that the Commission must review to meet its responsibilities under the Act and other Federal laws prior to issuance of even a new license for a previously licensed project.

AEP and Allegheny Electric Cooperative suggest that an applicant for a major project at an existing dam should not be required to provide various information required by the proposed rule insofar as that information would pertain to portions of a project that are owned by the Army Corps of Engineers or a state. In response to those comments, a provision has been added to Exhibit A (§ 4.51(b)) to eliminate from the reporting requirements information on project works (which includes dams and reservoirs) maintained or operated by the Corps, the Bureau of Reclamation, or other Federal agency or department.[17] This provision will also have the effect of eliminating information that would otherwise have been required for those project works by references to Exhibit A in Exhibits C and D. It also reduces the extent of the project boundary and the report on land use and aesthetics in Exhibit E.

The Department of the Interior desires that no license or permit be granted for a project which is Federally funded or is being considered for Federal construction. The Commission will not accept an application for a project that is authorized by law for Federal development (*see* § 4.30 (b) and (c) in the final regulation issued in Docket No. RM 79–23).[18] However, it is beyond the scope of this rulemaking to include, as DOI also requests, provisions which make applicants aware of the many Federal programs or limitations emanating from other agencies that may or may not apply to particular projects. Compliance with applicable Federal laws is the responsibility of a licensee.

The Power Authority of New York (PANY) suggested, as it did in Docket No. RM–79–23, that the Commission retain reference to "minor part" licenses. This suggestion is rejected for the reason stated in that docket, namely that such licenses were issued under erroneous conclusions of law and are also inappropriate under the new licensing provisions.

Exhibit D is a statement of costs and financing for the new development. PG&E contends that some aspects of the statement require too much detail (§ 4.51(e)(3)(ii)), such as the submission of quantity and unit costs. PG&E also argues that cost estimates of that detail may put the applicant at a disadvantage with prospective suppliers if the expected price of those items has already been made a matter of public record. The relevant phrases in § 4.51(e)(3)(ii) have consequently been modified to require only the total costs of the various components of the new development. If quantity and unit costs are needed in assessing a particular project at existing dams, however, they may be required as additional information according to the facts of the case.

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[16] Notice of Proposed Rulemaking, Docket No. RM79-35, 44 FR 24580, April 26, 1979.

[17] Project works owned and operated by a state, however, are subject to licensing under section 23(b) of the Act and would have to be covered by an application for license, whether the state filed as a joint applicant or as a separate applicant for only its part of the "complete unit of development," as defined in section 3(11) of the Act.

[18] For projects merely being studied for Federal development, the Commission is not precluded from issuing a preliminary permit if an applicant wishes to study the project concurrently. With respect to an application for a license, the Commission will consider whether to recommend Federal development under section 7(b) of the Act instead of issuing a license.

Idaho Power Company states that the information requested in paragraphs (3), (4), and (5) of § 4.51 is also supplied on a continuing basis on Forms 6 and 1. It should be pointed out that those forms are submitted only after a license is granted, not before. Furthermore, the Commission prefers that each application be a self-contained document so that not only Commission staff but other Federal agencies and intervenors may fully understand the proposed project. With respect to licensed projects being relicensed, there should be no significant burden on the applicant in providing this information in the application, where it may be readily reviewed by interested persons and agencies other than the Commission itself.

AEP expresses uncertainty about how the new regulations will apply to applications filed under the existing requirements. Any application filed before the effective date of these regulations will not need to be refiled in accordance with the new regulations, if it is satisfactory under the existing regulations. If additional information is required for proper review, it will be requested under § 4.31(f). AEP also proposes language to be added to § 4.51(e)(5), Exhibit D, which is a statement of the estimated annual value of project power. AEP argues that in computing true value, it is important to take cognizance of the rising cost over time of energy from alternative sources. Since the Commission agrees with this point, the following phrase is added to the subparagraph: "* * * specifying any projected changes in the cost of power from that source over the estimated financing or licensing period if the applicant takes such changes into account * * *." To make a valid comparison, however, § 4.31(e)(4) is being modified similarly, with respect to the annual cost of project power. The language of § 4.51(e)(5) is also clarified to indicate that "annual" values of power and cost of the "lowest cost" alternative sources is what the statement requires.

AEP points out that proposed § 4.51(a)(5) may be construed to be inconsistent with the *First Iowa* decision.[19] In that case, the Supreme Court held that state permit requirements or other laws inconsistent with the Federal water power project licensing scheme were preempted by the Federal Power Act. The Court also declared that under section 9(b) of the Act, the Commission need not require an applicant to show that it has complied with state laws governing stream bed and banks and appropriation, diversion, or use of water for power purposes and the right to engage in the business of developing, transmitting, and distributing power and in other businesses necessary to effect the purposes of a license. Instead, the Court interpreted section 9(b) as calling for satisfactory evidence of any steps taken or progress made by the applicant toward meeting local requirements insofar as those laws were not superseded by the Act. 328 U.S. at 177–178. To clarify this matter, the final regulation contains a new § 4.51(a)(5), requiring that the applicant cite and briefly describe the state laws of the types set forth in section 9(b) of the Act that are relevant to the development of this project and briefly state what measures it has taken or plans to take with respect to compliance with such statutory or regulatory requirements.

Finally, APS requests that the distinction between minor (not more than 1.5 MW installed capacity) and major water power projects be revised upward to encourage development of small projects. The distinction is found in section 10(i) of the Act and reclassification of major projects to include those with capacities over 5, 10, or 15 MW must therefore be left to Congress.

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[19] *First Iowa Hydro-Electric Cooperative v. F.P.C.*, 328 U.S. 152 (1946). *See also* 51 F.P.C. 581, 1797, 1939, and 1970 (1974).

III. Section-by-Section Analysis

§ 2.81(a) Compliance with the National Environmental Policy Act of 1969 under Part I of the Federal Power Act

The existing § 2.81(a) relies on Appendix A as the standard environmental report provision for all major water power projects. This section is revised to direct applicants for major projects at existing dams to submit an Environmental Report under § 4.51(f), the new Exhibit E.

§ 4.50 Applicability and definitions.

This section states that §§ 4.50 and 4.51 pertain to any application for an initial license, or a new license for a major project-existing dam. The section also provides definitions of certain key terms which appear in §§ 4.50 and 4.51. The definition of "major project-existing dam" makes clear that proposed construction or repair with certain environmental consequences places an application outside the scope of this subpart. Finally, the section offers the assistance of the Commission staff in determining whether §§ 4.50 and 4.51 apply to a given project.

§ 4.51 Contents of application.

This section contains the specific requirements governing the contents of an application for a license for a major project-existing dam. The requirements are embodied in an initial statement and seven lettered exhibits.

Initial statement. Under paragraph (a), an applicant must submit an initial statement. The initial statement provides certain basic information necessary for identification and orientation purposes, including the nature of the application, the names and business addresses of the applicants, and the name and location of the project. The applicant must also inform the Commission of any state law of the kinds listed in Section 9(b) of the Act to which the proposed project is subject and steps it will take in compliance.

Exhibit A. This exhibit is described in paragraph (b) and provides a description of the physical structures and features of the project. If the project includes more than one dam and associated facilities, each such discrete development must be described. The exhibit also includes a tabulation of any lands of the United States that are enclosed within the project boundary.

This tabulation is necessary in order to record accurately the lands which have been reserved from entry, location, or other disposal pursuant to section 24 of the Act, 16 U.S.C. 818.

Exhibit B. Paragraph (c) describes a statement of project operation and resource utilization. This exhibit calls for a description of the available resource (flow and head) and technical documentation of the manner in which the applicant proposes to utilize that resource for the generation of power. The applicant must also explain how it intends to dispose of the power. Finally, the applicant must describe any plans for future hydroelectric development on the affected stream.

Exhibit C. This exhibit, described in paragraph (d), is a construction history and a proposed construction schedule for the project. The construction history, which is required to be filed only if the applicant is seeking an initial license, calls for a tabulated chronology of construction for the existing project structures and facilities, including the dates of commencement and completion of construction or installation, and the dates of commencement of commercial operation. An applicant seeking a license for a proposed project at an existing dam would only be expected to give its best available information, if precise dates for the dam and any other existing structures are not available.

The proposed construction schedule is required only if new development at the project is proposed.

Exhibit D. This exhibit is a statement of costs and financing and is described in paragraph (e). If the applicant seeks a new license for a constructed project, and is not a municipality or a state, it must provide an estimate of the amount that would be payable if the United States exercised its right to take over the project upon expiration of the current license, pursuant to section 14 of the Act, 16 U.S.C. 807.

If the applicant seeks an initial license, information concerning the original cost of land or water rights and existing project works must be provided. Estimated costs of any proposed new development and estimated annual costs must also be provided, as well as information concerning the value of project power to the applicant and the sources and extent of financing and annual revenues available to meet the estimated costs.

Exhibit E. This exhibit is a report on the environmental resources of the project, the impacts of the project on those resources, and the proposed measures to mitigate the impacts or to protect and enhance the resources. It is described in paragraph (f).[20]

The Commission has given notice in a related rulemaking[21] that the Environmental Report for a major project at an existing dam must also include an evaluation of a project's impact on wetlands and floodplains. Accordingly Exhibit E requires description of such areas in the vicinity of the project (§ 4.51(f) (1) and (6)), as specified in the preamble of that proposed rulemaking. Each applicant must report the project's short-term and long-term impacts on these areas and any mitigative measures to be taken in the construction or operation of the project if the project is approved. Any changes made in the final version of the rulemaking in Docket No. RM79-70 that would affect the Commission's treatment of floodplains and wetlands may result in further modification of the provisions in this docket.

The exhibit requires applicants to consult with local, state, and Federal agencies with expertise in environmental matters prior to filing their applications. An applicant must document the consultation by appending to its report a letter from each agency consulted summarizing the nature and extent of the consultation.[22]

Exhibit F. Paragraph (g) describes the general design drawings of the principal project works to be included in Exhibit F. The drawings must show plans, elevations, profiles, and sections for each structure, and must be accompanied by sufficient information concerning structural strength and stability and other controlling factors to demonstrate that the structures are safe and adequate for their stated functions. *See* section 10(c) of the Act, 16 U.S.C. 803(c).

Detailed working drawings showing the precise plans and specifications for proposed project structures are not to be filed with the application, but should be prepared for the purposes of construction and retained after construction is completed as permanent project records.

Exhibit G. As described in paragraph (h), the final exhibit is a map of the project. The map must show the geographical location of the project, the physical interrelationships of project works and other features, a project boundary enclosing the project works and all lands and waters necessary for project purposes, and any lands of the United States that are within the project boundary.

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[20] The exhibit must include reports on water use and quality; fish, wildlife, and botanical resources; historical and archeological resources; recreation resources; and land management and aesthetics.

[21] Notice of Proposed Rulemaking, Floodplain Management and Protection of Wetlands, issued August 20, 1979, 44 FR 49466, Docket No. RM79-70.

[22] Several statutes, including PURPA, require the Commission to consult with other agencies. Section 405 of PURPA provides that, prior to issuing a license for a project which fits the PURPA criteria, the Commission must "provide an opportunity for consultation with the Council on Environmental Quality and the Environmental Protection Agency with respect to the environmental effects of such project." This duty will be carried out in accordance with our established procedures for consultation during the license application review process. Moreover, in certain circumstances, other agencies may have concurrent jurisdiction with respect to authorization of a project. Prior consultation by applicants will facilitate coordination with these other agencies.

The following table illustrates how the information required under the former regulations has been eliminated or transferred to the new regulations:

Former Regulations for Major Projects and New Regulations for Only Major Projects—Existing Dams

§§ 4.50–4.51—§§ 4.50–4.51
4.40(a)—4.51(a)(1), (3)
4.40(b)—4.51(a)(3), (4)
4.40(c)—*
4.40(d)—*
4.40(e)—4.51(b)—Exhibit A
4.40(f)—4.51(a)(2)
4.40(g)—4.51(b)(6)
4.40(h)—4.51(c)—Exhibit B
4.40(i)—4.51(c)—Exhibit B
4.40(j)—*
4.40(k), (l)—4.51(f)—Exhibit E
4.40(m)—*
§ 4.41 Exhibits:
A—*
B—*
C—*
D—4.51(a)(5)
E—4.51(a)(5)
F—*
G—4.51(e)—Exhibit D(6)
H—4.51(c)—Exhibit B
H—4.51(f)—Exhibit E
I—4.51(c)—Exhibit B
J—4.51(h)—Exhibit G
K—4.51(h)—Exhibit G
L—4.51(g)—Exhibit F
M—4.51(b)—Exhibit A
N—4.51(e)—Exhibit D
O—4.51(d)—Exhibit C
P (§ 4.51)—*
Q (§ 4.51)—4.51(d)—Exhibit C
R—4.51(f)(5)—Exhibit E
S—4.51(f)(3)—Exhibit E(3)
T—*
U—4.51(c)—Exhibit B
V—4.51(f)(4)—Exhibit E and (6)
W—4.51(f)—Exhibit E
Appendix A to Part 2—4.51(f)—Exhibits E

An applicant or licensee may have an obligation to file exhibits under the old regulations pursuant to a Commission order, even after the effective date of these regulations. Requests to waive or amend any requirement to submit an exhibit under the old regulations, and to be permitted to file under the new regulations, may be submitted to the Director of the Office of Electric Power Regulation.

Other provisions amended or revoked. Besides the revisions to §§ 4.50 and 4.51, the Commission is changing certain other existing rules and regulations.

Section 16.6 of the regulations governing applications for new licenses has been revoked. Most of the provisions of § 16.6 have been incorporated in the amended § 4.51. The provisions of § 16.6(e) have been eliminated, however. They formerly required a licensee-applicant who is not a municipality or a state to file a statement on the effect that takeover by the United States or issuance of a license to another applicant would have upon the supply of electric energy to the system with which it is interconnected, the rates charged its customers, its financial condition, and taxes collected by local, state, and Federal governments. In a situation where there is a competing application, or a recommendation for Federal takeover, this information may be desirable and could be requested as a supplemental filing. If such situations became commonplace, the requirement could be reinstated in the regulations.

IV. Effective Date

These revisions in Part 2, 4 and 16 of the Commission's regulations will be effective January 1, 1980.

(Federal Power Act, as amended, 16 U.S.C. 792–828c; Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601–2645; Department of Energy Organization Act, 42 U.S.C. 7101–7352; Executive Order No. 12009, 42 FR 46267)

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* No equivalent applies to major projects—existing dams.

In consideration of the foregoing, the Commission amends Part 2 of Subchapter A and Parts 4 and 16 of Subchapter B, Chapter I, Title 18, Code of Federal Regulations, as set forth below.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,107]

44 F. R. 68819 (November 30, 1979)

18 CFR Part 284

[Docket No. RM79–74; Order No. 60]

Interstate Pipeline Transportation on Behalf of Other Interstate Pipelines

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (FERC) adopts a blanket certificate procedure to permit interstate pipelines to transport natural gas for delivery to other interstate pipelines. Any interstate pipeline which holds a blanket certificate could transport natural gas under the terms applicable to transportation authorized under section 311(a)(1) of the Natural Gas Policy Act of 1978 without prior FERC approval of each individual transaction.

EFFECTIVE DATE: November 21, 1979.

FOR FURTHER INFORMATION CONTACT:

Robert C. Platt, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357–8454.
Robert J. Cupina, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357–9031.

November 21, 1979.

I. Background

The Commission issued a proposed rule on August 27, 1979, which provides for blanket certificates to authorize transportation by interstate pipelines on behalf of other interstate pipelines.[1] After conducting a public hearing on September 24, 1979, and analyzing comments received on the proposal the Commission is promulgating a final rule to implement this proposal.

Section 311(a)(1) of the Natural Gas Policy Act of 1978 (NGPA), 15 U.S.C. 3371(a)(1), enables the Commission to authorize transportation by an interstate pipeline on behalf of any intrastate pipeline or local distribution company. However, transportation by an interstate pipeline on behalf of a second interstate pipeline is beyond the scope of section 311 of the NGPA. Such transportation arrangements require certificates of public convenience and necessity pursuant to section 7(c) of the Natural Gas Act.

This gap in the Commission's section 311 authority may place a greater regulatory burden on an interstate pipeline transporting natural gas for other interstate pipelines than would be required if the interstate pipeline were transporting on behalf of an intrastate pipeline or a local distribution company. Unlike section 311 authorizations which can be implemented on a self-executing basis (See 18 CFR 284.102), certificates under section 7(c) of the Natural Gas Act are issued only after a case-by-case review. Hence, under section 311 an intrastate pipeline or local distribution company seeking to attach new supplies through interstate pipeline transportation may implement such a transaction for a two year period without prior Commission approval. However, if an interstate pipeline sought the same supply for its customers, the transaction would require the Commission to issue at least a temporary certificate before a second interstate pipeline could transport the natural gas to the purchasing interstate pipeline. In view of the Commission's desire to increase system supplies available to interstate pipelines as well as to reduce the regulatory burden on the interstate pipelines transporting those supplies, the Commission has determined that case-by-case review of each such tranportation arrangement is inconsistent with the public interest at this time.

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[1] 44 Fed. Reg. 51812 (September 4, 1979).

In place of individual applications for each transportation arrangement, the final rule would allow the transporting interstate pipeline to apply for a one time blanket certificate which would authorize all transportation services on behalf of other interstate pipelines for periods of up to two years. Although such transportation would remain subject to the Commission's Natural Gas Act jurisdiction, the terms and conditions attached to the certificate (except for the application procedure in § 284.107) would be identical to those imposed by Subpart B of Part 284.

II. Public Convenience and Necessity

The Commission finds that the transportation authorized by these blanket certificates is required by the present or future public convenience and necessity.[2]

Several factors underlie this finding. First, the natural gas will enter the general system supplies of an interstate pipeline, rather than benefiting specific end-users. Second, the natural gas will be subject to end-use allocation under Commission approved curtailment plans. Third, individual transactions under the blanket certificate are short-term (two years or less) and would not disrupt markets upon which interstate pipelines have traditionally relied.

III. Summary of Comments

Fifteen comments were filed in response to the proposed rule. The written comments and presentations at the public hearing focused upon the treatment of transportation revenues, the scope of the blanket certificate authorization, and clarification of other certificate conditions.

A. *Crediting of Revenues.* Paragraph (d) incorporates the treatment of revenues specified in § 284.103(d), which governs transportation by interstate pipelines authorized by section 311(a)(1) of the NGPA. Section 284.103(d) provides a one cent per MMBtu allowance for out-of-pocket costs. If the revenues subject to § 284.103(d) fall within representative levels which have been credited in arriving at a test period cost of service or if the volumes transported fall within those representative levels used in establishing the pipeline's current rates, the pipeline retains the revenues from the transportation. However, if the pipeline receives revenues in excess of those provided in determining the pipeline's rates, then § 284.103(d) requires the revenues in excess of out-of-pocket costs to be credited to the pipeline's customers through Account 191. Several comments suggested increasing the one cent out-of-pocket cost allowance to five cents, and another comment suggested allowing the pipeline to retain 50 percent of all transportation revenues as an "incentive." The final rule does not incorporate either suggestion. A pipeline is permitted to recover demonstrated out-of-pocket costs in excess of one cent per MMBtu under § 284.103(d)(3). Any revenues retained by the pipeline which are not a reimbursement of out-of-pocket costs represent a double recovery of costs by the pipeline from both its regular ratepayers and those served under the blanket certificate.

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[2] Similar blanket transportation certificates have been issued in the past. High Island Offsore System and U-T offshore System, Docket Nos. CP75-104 and CP78-118. Order issued June 12, 1978.

One comment suggested that the pipeline's out-of-pocket costs be debited to Account 191. Because only revenues in excess of out-of-pocket costs (as represented by the one cent allowance or a demonstrated greater amount) are credited to Account 191, a further debiting of Account 191 would represent a double recovery of costs by the pipeline. Accordingly, the Commission rejects the suggestion.

One comment questioned the effect of a general rate settlement upon the requirements of § 284.103. An applicant for a blanket certificate may call to the Commission's attention any provision of a previous settlement which may conflict with the requirements of § 284.103(d). However, unless otherwise provided in the order granting the blanket certificate, the provisions of § 284.103(d) will apply to all transactions covered by the certificate.

B. Scope of the Blanket Certificate

Several comments questioned the limitation that the transportation by an interstate pipeline must be "on behalf of any other interstate pipeline." In general, the Commission's interpretation of the phrase "on behalf of" in the context of section 311 of the NGPA is equally applicable to determining the scope of any blanket certificate issued under the final rule.[3] This requirement excludes the transportation of the pipeline's own system supplies through the pipeline's own facilities for two reasons. First, such transportation is authorized by the pipeline's existing certificates covering the transportation and sales for resale of its system supplies. Second, the certification of new loads to be served from the system supplies of an interstate pipeline is central to the Commission's responsibilities under the Natural Gas Act and should not be authorized on a self-implementing basis. For this reason the transportation of the pipeline's own volumes will continue to be excluded. Although transportation of natural gas owned by a pipeline through the pipeline's own facilities is not covered, any transportation by an interstate pipeline of a second interstate pipeline's system supplies is within the scope of the blanket certificate. Such transportation would be eligible even if other intermediaries transport the natural gas before reaching the second pipeline's facilities.

A comment sought clarification of whether the blanket certificate would be limited to the transportation of newly acquired natural gas supplies. The final rule permits either new or existing supplies to be transported under the blanket certificate.

Another comment sought explicit inclusion of offshore pipelines within the scope of the blanket certificate. As promulgated, the rule applies equally to both onshore and offshore pipelines.

A comment sought to reduce the scope of the blanket certificate. The comment recommended imposing a two year limit on the duration of the initial blanket certificate (as opposed to individual transactions). Renewals of the blanket certificate would be granted only if the holder of a blanket certificate demonstrated "good faith continuing efforts to reduce curtailments and increase system supplies." The comment claims that this renewal procedure would provide an incentive for the certificate holder to reduce curtailments to its customers. However, the Commission notes that most interstate pipelines are already under such a service obligation under their outstanding certificates. Given the general improvement in the curtailment levels of most interstate pipelines, such a limitation is not necessary.

C. Construction of Facilities

A number of comments suggested expanding the budget-type certificate for the construction of gas purchase facilities to include transactions authorized by a blanket certificate. The Commission's final rule issued on November 1, 1979 in Docket Nos. RM79–37 and RM79–43 addresses these concerns. Facilities incidental to a transaction authorized by a blanket certificate meet the definition of "gas supply facilities" in § 157.7(b)(4) of this chapter and may be construed without an individual certificate under section 7(c) of the Natural Gas Act. The final rule contains a reference to this provision.

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[3] No. See Order No. 46, issued August 30, 1979, 44 FR 52179 (September 7, 1979) at n.8.

IV. Section by Section Analysis of the Final Rule

Paragraph (a) of § 284.221 clarifies the relationship between the blanket certificate and the self-executing authorizations in Subpart B of part 284; *i.e.* the blanket certificate covers only natural gas transported by interstate pipelines for the system supplies of other interstate pipelines. The transportation of the interstate pipeline's own natural gas is not covered by the blanket certificate. Under paragraph (d), long term transportation arrangements are also excluded from the blanket certificate. However, the blanket certificate may be used to commence a long term transaction while an application for a permanent certificate of public convenience and necessity is pending.

Paragraph (b) indicates the limited nature of the blanket certificate. Although the certificate is of indefinite duration, individual transactions authorized under it are limited to two years in accordance with § 284.105. An interstate pipeline may file for a blanket certificate even if the pipeline has not arranged for any specific transactions at the time of the application.

Paragraph (c) prescribes an abbreviated application procedure. Because data on individual transactions will be filed within thirty days of the commencement of each transaction in accordance with § 284.106, detailed data is not required for the blanket certificate application. In addition, the filing of a summary report will also be required under § 284.4, with 48 hours of the commencement of each transaction covered by the blanket certificate.

Paragraph (d) incorporates by reference the conditions set forth in Subpart B of Part 284 as amended from time to time. Although all provisions of Subpart B are incorporated, only those relating to self-implementing transactions for periods of up to two years are relevant. Hence, the application procedure of § 284.107 is not applicable. A clarifying and conforming change has been made in § 284.107.

Paragraph (e) frees the holder of the blanket certificate from any continuing service obligation after each underlying transportation contract expires. The Commission intends to grant abandonment authority at the same time that its grants a blanket certificate as part of its policy of placing the holder of a blanket certificate in an equivalent position to a transporter authorized under section 311(a)(1) of the NGPA.

Paragraph (f) makes clear that interstate pipelines may still obtain section 7(c) authorization on a case-by-case basis for specific transportation arrangements which would otherwise be authorized by the blanket certificate, regardless of whether or not the interstate pipeline holds a blanket certificate.

Paragraph (g) includes a cross-reference for the Commission's budget-type certificate procedures to authorizing the construction of gas purchase facilities. If a transaction requires the construction of facilities which are subject to the Commission's Natural Gas Act jurisdiction, the holder of a blanket certificate must also hold a budget-type certificate issued pursuant to § 157.7(b) in order that the transaction may commence without prior Commission approval.

V. Effective Date

Because of the need to encourage the attachment of new supplies to the interstate natural gas market and time constraints imposed by the onset of the winter heating season, the Commission finds that good cause exists to make this rule effective immediately. 5 U.S.C. 553(d)(3).

(Natural Gas Act, 15 U.S.C. 717 *et seq.*; Department of Energy Organization Act, 42 U.S.C. 7107 *et seq.*; E.O. 12009, 42 FR 46267).

In consideration of the foregoing, the Commission is adding a new Subpart G to Part 284, Subchapter I, Chapter I of Title 18, Code Federal Regulations, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,108]

44 F. R. 69284 (December 3, 1979)

18 CFR Part 1

[Docket No. RM79-32; Order No. 24-A]

Procedures for Adjustments of Rules and Orders Issued by the Federal Energy Regulatory Commission Under the NGPA

AGENCY: Federal Energy Regulatory Commision, DOE.

ACTION: Amending interim rule.

SUMMARY: The purpose of the amendment is to clarify interim rules issued on March 22, 1979, under Docket No. RM79-32, 44 FR 18961. The clarification, and amendment to § 1.41(a) of the Commission's regulations, provides that procedures for requests for adjustments under section 502(c) of the NGPA will not apply when waived by the Commission or when adjustments are granted under the Commission's own motion.

DATES: Amendments effective November 27, 1979; Notice of intent to participate in oral presentations and written comments by December 14, 1979; oral presentations on December 19, 1979.

ADDRESS: Notice of intent to participate in oral presentations and written comments should reference Docket No. RM79-32 and should be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426.

Oral presentations to be held at the Offices of the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426

FOR FURTHER INFORMATION CONTACT: MaryJane Reynolds, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Room 8000, Washington, D.C. 20425 (202) 357-8455

November 27, 1979.

A. Background

On March 22, 1979, the Federal Energy Regulatory Commission (Commission) issued interim regulations implementing procedures whereby any person may seek an adjustment from Commission rules and orders issued under the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3301 to 3432). Order No. 24, Docket No. RM79-32 (44 FR 18961, March 30, 1979). These interim procedural regulations implement provisions of section 502(c) of the NGPA.[1] However, these interim procedural regulations did not specifically address the issue of waiver.

Section 1.41 was created to provide a mechanism by which those affected by

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[1] Section 502(c) of the NGPA provides that: [t]he Commission or any other Federal officer or agency authorized to issue rules or orders described in subsection (a) (other than an order under section 301, 302, or 303) shall, by rule, provide for the making of such adjustments, consistent with the other purposes of this Act, as may be necessary to prevent special hardship, inequity, or an unfair distribution of burdens. Such rule shall establish procedures which are available to any person for the purpose of seeking an interpretation, modification, or rescission of, exception to, or exemption from, such applicable rules or orders. If any person is aggrieved or adversely affected by the denial of a request for adjustment under the preceding sentence, such person may request a review of such denial by the officer or agency and may obtain judicial review in accordance with section 506 when such denial becomes final. The officer or agency shall, by rule, establish procedures, including an opportunity for oral presentation of data, views, and arguments, for considering requests for adjustment under this subsection.

Commission rules or orders issued under the NGPA could apply for, and be granted (if appropriate), an adjustment of those rules or orders. When issued, the interim regulations of § 1.41 did not specifically include provisions for submissions which did not comply with the provisions of § 1.41 or adjustments considered on the Commission's own motion. Instead, such situations have been handled on a case-by-case basis.

B. Discussion

The Commission reviews and acts upon a large number of diverse filings under the regulations implementing the NGPA. This review function provides a useful method whereby the Commission becomes aware of circumstances which require remedial or other corrective action. The Commission must also deal with petitions received under § 1.41 which, for one reason or another, do not comport with the filing requirements of that section or are not amenable to the procedures of that section.

The changes made today explicitly provide for a waiver of the procedures of § 1.41 for those cases which, while not filed under or in accordance with the provisions of that section, should nonetheless be considered for adjustments because of the issues they raise. We believe that this amendment effects the flexible approach inherent in section 502(c) of the NGPA and permits the Commission to proceed expeditiously to the substance of filings and the question of adjustment.

C. Effective Date and Public Procedures

These revisions to the interim regulations of § 1.41 are being issued as interim rules effective immediately. The regulations of § 1.41 and these amendments are procedural and relate to practice before the Commission. In addition, there is an immediate need to have regulations which aid in the Commission's full and effective implementation of section 502(c) of the NGPA. For these reasons, the Commission finds that good cause exists to adopt the revisions of this order effective immediately.

Although effective immediately, the amendments of this order are interim regulations. In order to consider appropriate comments prior to issuing a final rule, the Commission is affording an opportunity for interested persons to submit written comments, data, views or arguments regarding this Order. An original and 14 conformed copies of the comment should be filed by December 14, 1979 with the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. Each comment should include the name and address of the person submitting the comment, should reference Docket No. RM79-32, and should include reasons for any recommendations. Comments should indicate the name, title, mailing address and telephone number of one person to whom communications concerning the amendment may be addressed. Written comments will be placed in the Commission's public file and will be available for public inspection during regular business hours at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street N.E., Washington, D.C. 20426.

Because this order amends a regulation issued under the NGPA, the Commission will provide an opportunity for the oral presentation of data, views and arguments on the Order as required by section 502(b) of the NGPA. A public hearing on this order will be held in Washington, D.C. on Wednesday, December 19, 1979. The hearing will be held at the Offices of the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C., and will begin at 10:00 a.m., local time.

Requests to participate in the hearing should be directed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. and should be made no later than December 14, 1979. Requests should reference Docket No. RM79-32 and should indicate the name of the person who will be making the presentation, a phone number at which that person may be contacted, and the amount of time requested for the presentation.

Persons participating in the public hearing should, if possible, bring 25 copies of their testimony to the hearing. A list of the participants in the hearing will be available in the Commission's Office of Public Information prior to the hearing and will be available at the Commission on the morning of the hearing.

The hearing will not be a judicial or evidentiary-type hearing, and there will be no cross examination of persons presenting statements. The presentations will be made before a panel whose members will be designated by the Chairman. Members participating on the panel before whom the presentations are made may ask questions. If time permits, they may also ask such relevant questions as are submitted to them by participants. Other procedural rules relating to the hearing will be announced at the time the proceedings commence. A transcript of the hearing will be made and a copy of that transcript will be placed in the public file for this docket and be made available at the Commission's Office of Public Information.

(Natural Gas Policy Act of 1978, Pub. L. No. 95–621, 92 Stat. 3350; Department of Energy, Organization Act, Pub. L. No. 95–91, 91 Stat. 565, et seq., E.O. 12009, 42 FR 46267; Natural Gas Act, as amended, 15 U.S.C. 717 et seq.)

Inconsideration of the foregoing, Part 1, Subchapter A, Chapter I of Title 18 of the Code of Federal Regulations is amended as set forth below, as an interim regulation, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,109]

44 F. R. 69642 (December 4, 1979);
44 F. R. 76778 (December 28, 1979).

18 CFR Parts 271 and 274

[Docket No. RM79–68; Order No. 42–A]

Final Rules Amending Regulations on New Natural Gas and Certain Natural Gas Produced From the Outer Continental Shelf

AGENCY: Federal Energy Regulatory Commission.

ACTION: Order Amending Final and Interim Regulations and Denying Motion for Reconsideration and Granting in Part and Denying in Part Petitions for Rehearing of Order 42.

SUMMARY: This regulation amends the final regulations implementing section 102 of the Natural Gas Policy Act of 1978 which sets ceiling prices for new natural gas and certain natural gas produced from the outer continental shelf. This regulation also amends the filing requirements to reflect the changes made in the final regulations.

EFFECTIVE DATE: November 29, 1979.

FOR FURTHER INFORMATION CONTACT: Scott Koves, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357–8317.

[Order No. 42–A]

Order Denying Motion for Reconsideration and Granting in Part and Denying in Part Petitions for Rehearing of Order No. 42

Issued: November 29, 1979.

I. Background

On August 14, 1979, the Federal Energy Regulatory Commission (Commission) issued Order No. 42 in Docket No. RM79–68.[1] Applications for rehearing of that order were filed on September 13 and 14, 1979 by several parties [2] (Petitioners), pursuant to § 286.102 of the Commission's regulations. On October 10, 1979, Indicated Producers filed a Motion for Reconsideration of Order No. 42.

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[1] Published on August 17, 1979, at 44 FR 48180.

Order No. 42 issued Final Regulations for Subpart B of Part 271 of the Commission's regulations which implements section 102 of the Natural Gas Policy Act of 1978, 15 U.S.C. 3301, *et seq.* (NGPA). Section 102 of the NGPA applies to the first sale of new natural gas. Order No. 42 revised the Commission's interim regulations under the NGPA issued December 1, 1978, in Docket No. RM79–3 [3] and issued Part 271, Subpart B as final regulations. On October 15, 1979, the Commission issued an order granting rehearing to permit further consideration of the issues raised in the petitions for rehearing.

II. Specifications of Error

A. NGPA section 102(c)(1)(C)(ii)(II)—the Behind-the-Pipe Exclusion

Section 102(c)(1)(C) of the NGPA applies to gas produced from "new onshore reservoirs" which are generally defined as onshore reservoirs from which natural gas was not produced in commercial quantities before April 20, 1977. Under the Behind-the-Pipe exclusion, if an old well penetrated the subject reservoir and produced oil or gas in commercial quantities prior to April 20, 1977, the penetrated reservoir is disqualified if gas from that reservoir "could have been produced in commercial quantities" through such old well prior to April 20, 1977.

In Order No. 42, for the reasons discussed, we decided to apply a physical capability test in determining whether gas "could have been produced in commercial quantities" from the subject reservoir. The test only inquires into the capability of the reservoir to produce. Such a physical capability test disregards costs of production and marketing.

Order No. 42 rejected use of an economic test for determining whether gas could have been produced from the reservoir in commercial quantities. Petitioners made various arguments in favor of applying an economic test. Chief among these were the following: (a) The Commission ignored the plain words of the statute by giving no effect to the phrase "in commercial quantities." (b) The Commission inappropriately applied the explanation in the Statement of Managers [4] (page 79) to both components of the phrase "could have been produced"—"in commercial quantities" because the analysis referred only to the phrase "could have been produced." (c) The Commission's interpretation contradicts customary usage of the term "commercial." (d) The legislative history of the NGPA supports the view that Congress intended that an economic test be used to determine whether gas could have been produced in commercial quantities. (e) The Commission's interpretation of the Behind-the-Pipe Exclusion frustrates Congress' policy permitting incentive prices in order to encourage production of previously uneconomical reserves.

We agree that the statutory language, "could have been produced in commercial quantities" must be interpreted and applied in its entirety. A physical capability test should be used for "could have been produced"; an economic test should be used for "in commercial quantities." Therefore, the Commission agrees that it must use both a physical capability test and an economic test in determining whether the reservoir is disqualified by the Behind-the-Pipe Exclusion.[5]

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[2] True Oil Company; Harvey E. Yates Company and the Independent Petroleum Association of New Mexico; Texas Oil & Gas Corp., Amoco Production Company; Houston Oil & Minerals Corp., Goldking Production Company, Texas Production Company, Pinto, Inc., Ecee, Inc., and Cliffs Drilling Company; and Tenneco Oil Company, Pennzoil Company, Texas Gulf, Inc., General American Oil Company of Texas. Energy Consumers and Producers Association filed comments on September 4, 1979, which we will consider herein.

[3] Published on December 1, 1978, at 43 FR 56448, *et seq.*

[4] Joint Explanatory Statement of the Committee on Conference, Natural Gas Policy Act of 1978, P.L. 95–621, S. Rep. No. 95–1126, August 18, 1978.

None of the subject applications for rehearing articulated a specific economic test. However, several Petitioners argued that the rebuttable presumption in section 102(c)(3)[6] should be applied in determining whether gas "could have been produced in commercial quantities". Under such a rule, there would be a rebuttable presumption that the Behind-the-Pipe Exclusion would not apply unless actual sales and deliveries had been made from the subject reservoir, prior to April 20, 1977. Thus, the burden of proving the lack of capability to produce in commercial quantities would be shifted to protestants or the jurisdictional agency because the protestants or agency would have to prove such capability existed.

We reject this suggestion. The rebuttable presumption prescribed in section 102(c)(3) applies only to the question of whether gas *has* been produced in commercial quantities, not whether it *could* have been produced. Imposing a rebuttable presumption which would require only that actual sales had not been made prior to April 20, 1977, would all but eliminate the Behind-the-Pipe Exclusion, and would impose an unreasonable administrative burden on jurisdictional agencies by improperly shifting the burden of proof to them in all cases.[7]

One Petitioner suggests that the gas should not be disqualified under the Behind-the-Pipe Exclusion if there were no marketing facilities, such as a gathering system, on April 20, 1977. We do not agree that the absence of marketing facilities is dispositive. While the Statement of Managers, at page 79 directed the application of a physical capability test in determining whether a reservoir could have been produced, that test is to be applied only with respect to the *reservoir's* physical capability to produce and not to whether "actual production capability existed". In other words, as stated by the conferees, "if the pipe were perforated, or if the necessary additional facilities were installed at the appropriate place, [the reservoir] *could have produced* natural gas." (Emphasis added). Therefore, the absence of marketing facilities does not automatically dispose of the issue of whether the reservoir could have been produced in commercial quantities.

However, the costs of installing additional necessary facilities will be recognized in considering whether such production would have been in commercial quantities.

We are adopting an economic test which we believe to be comprehensive, yet administratively feasible. However, we do not wish to impose this test and require the submission of economic data where there is very little likelihood that gas could have been produced in commercial quantities from the subject reservoir as of April 20, 1977. Therefore, we will require application of this test only if the potentially disqualifying well—that is, an old well which penetrated the subject reservoir before April 20, 1977, and produced oil or gas in commercial quantities before that date—does not meet either of the following conditions:

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[5] In recognition of this, the Commission issued a final order in Docket No. GP79-27 on September 28, 1979 which acknowledged that both a physical capability test and an economic test should be applied to the § 102(c)(1)(C) determination made by the State of North Dakota on the Gulf Oil Corp. State 1-18-3D, Martin Weber Weber 1-18-1C, Marinenko 1-32-1A, Glovatsky 1-17-4A, for the Little Knife Madison Reservoir. In that case, the sourness of the gas and the remoteness of the well was considered as evidence of the non-commerciality of the reserves in question prior to April 20, 1977.

[6] Among other things, section 102(c)(3) provides that, for purposes of section 102(c)(1)(C), a rebuttable presumption exists that production from a reservoir in commercial quantities has not occurred if natural gas has not been sold and delivered from such reservoir before April 20, 1977.

[7] We do believe that certain rebuttable presumptions are reasonable in these cases. (See discussion *infra*.) However, the section 102(c)(3) rebuttable presumption is not one of them.

(1) No sales and deliveries of natural gas were made prior to April 20, 1977, through the potentially disqualifying well.

(2) No sales and deliveries of natural gas from the subject reservoir were made through the potentially disqualifying well on or after April 20, 1977, and prior to November 9, 1978.

If both of these conditions are met, we will not require proof under an economic test because we will presume that the subject reservoir could not have been produced in commercial quantities through the potentially disqualifying well before April 20, 1977. This rebuttable presumption is in new paragraph (f)(1) of the special rule in § 271.204 and is incorporated in the filing requirements in § 274.202(d)(2)(ii)(D)(II).

The presumption is based on two components. The first recognizes that, if gas was not being produced and sold prior to April 20, 1977, from a potentially disqualifying well that penetrated the subject reservoir, then marketing facilities (gathering lines, processing facilities, and so forth) probably were not in existence as of that date and would have had to be installed at a considerable incremental cost.[9]

The second component of the presumption is based on the assumption that if no sales actually commenced from the subject reservoir within a reasonable time after April 20, 1977, from a potentially disqualifying well that penetrated that reservoir prior to April 20, 1977, then the subject reservoir probably was not commercial as of April 20, 1977. We have employed the date of enactment of the NGPA (November 9, 1978) as the cut-off date for this period. The generally higher ceiling prices permitted by the NGPA in many cases rendered marketable gas reserves which up until that time were not commercial.

We have incorporated this presumption into the reporting requirements in § 274.203 by limiting the reporting obligations of new paragraph (d)(2)(ii)(D) to those applicants who are unable to meet the presumption. This should reduce the number of applicants that may be required to submit further evidence as to the applicability of the Behind-the-Pipe Exclusion.

However, in the event that the rebuttable presumption of non-commerciality does not apply, then we believe it is reasonable to require the applicant to submit economic evidence that is substantially more convincing than would otherwise be required. Under these circumstances, the applicant must submit evidence that clearly demonstrates that the gas could not have been produced in commercial quantities from such reservoir through such old well before April 20, 1977. The new paragraph (d)(2)(ii)(D) to § 274.202 incorporates this requirement.

However, the Commission also recognizes that section 102(c)(1)(C), like section 102(d), involves a reservoir determination. Therefore, the determination that a reservoir is a new onshore reservoir need be made only once and can apply to all wells producing from the reservoir.

Furthermore, if it is necessary to apply an economic test, only one applicant need present such economic data. Thus, new § 274.202(d)(2)(ii)(D)(I) provides that if a final eligibility determination has been made determining that the subject reservoir qualifies as a new onshore reservoir, subsequent applicants need not meet the evidentiary showing required by new clause (ii)(D)(II) of § 274.202(d)(2) in order to demonstrate that the reservoir from which they are producing is not disqualified as a new onshore reservoir under the Behind-the-Pipe Exclusion. Once the applicant shows that such a final eligibility determination has been made, the applicant need only show that the well for which he seeks a determination is in fact producing from the reservoir that was previously determined to be a new onshore reservoir and that the Withheld Gas Exclusion, which is determined on a well-by-well basis, does not apply. Correspondingly, if a jurisdictional agency gives adequate notice and opportunity to participate in a proceeding and if one applicant receives a negative determination due to the fact that the reservoir has been disqualified because it was produced in commercial quantities prior to April 20, 1977, or because the Behind-the-Pipe Exclusion applied to the reservoir, and that determination has become final under § 273.102, all subsequent application relative to wells producing from the subject reservoir would also be disqualified under section 102(c)(1)(C).

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[9] This component focuses on gas produced from reservoirs other than the subject reservoir because, if gas was produced and sold from the subject reservoir prior to April 20, 1977, the reservoir was "produced in commercial quantities before April 20, 1977," and, according to section 102(c)(1)(C)(i) is disqualified as a new onshore reservoir.

The Commission believes that use of the rebuttable presumption will reduce the number of applicants who must file data to prove that a reservoir meets the economic test in § 274.202(d)(2)(ii)(D)(II) to a manageable number.

The economic test, stated in § 271.204, provides that a reservoir could have produced in commercial quantities if the sale of the production from the reservoir through the potentially disqualifying well could generate revenues (net of royalty) equal to or greater than the sum of (i) 1.6 times the minimum incremental costs (properly allocable to such production of installing post-April 20, 1977 facilities required to market such production, plus (ii) the minimum incremental expenses (properly allocable to such production) reasonably required to operate such facilities. All costs, expenses, and revenues are to be determined as of April 20, 1977.

In order to avoid the unmanageable administrative task of engaging in numerous proceedings dealing with the issue of appropriate return, we have made certain reasonable assumptions to derive this rule of thumb formula which reflects a minimum reasonable return. Based upon examination of the prime lending rate of 6.25 percent[9] as of April 20, 1977; the federal tax rate of 48 percent as of that date; and the after-tax return of less than 6.25 percent[10] on safe investments in the money market as of April 20, 1977, the Commission has determined 6.25 percent to be the appropriate after-tax rate of return. The rule of thumb formula approximately reflects an after-tax rate of return of 6.25% in the average case by multiplying incremental capital costs by a constant of 1.6.[11]

In accordance with the economic test, if the sale of the gas would have recouped the required costs, expenses and return, then the reservoir "could have been produced in commercial quantities" prior to April 20, 1977, and the Behind-the-Pipe Exclusion applies. In that case, gas from the reservoir would not qualify for the section 102 new onshore reservoir price. We are amending our regulations by adding a new paragraph (f)(1) to § 271.204 which incorporates the economic test set forth herein in the definition of the phrase "could have been produced in commercial quantities", and by adding a new paragraph (d)(2)(ii)(D)(II) to § 274.202 of the filing requirements.

The key components of this test are estimates of reserves, costs, and the market price of the gas. The following formula is to be used in applying the economic test: [(market price available as of April 20, 1977) × (reserves net of royalty producible from the subject

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[9] Federal Reserve Bulletin, No. 5, Vol. 63, May 1977, page A28, Table 1.34.

[10] Federal Reserve Bulletin, No. 5, Vol. 63, May 1977, page A27, Table 1.36.

[11] See Appendix A for further explanation.

reservoir through the potentially disqualifying wells)] — [(incremental operating expenses) + (1.6 × incremental capital costs)]. If the result is negative, then the exclusion does not apply. In order to maintain a relatively simple economic test we shall assume that escalations in the additional capital costs and operating expenses would be offset by escalations in the price applicable to the sale. Furthermore, we will assume that the effects of the time value of money will likewise be offset. Therefore, all costs, expenses, and revenues will be viewed as of one time frame, April 20, 1977. We are making these and other assumptions because we cannot justify requiring extensive special relief-type proceedings to determine whether or not the Behind-the-Pipe Exclusion applies for each of what may be a substantial number of onshore reservoirs.

According to the test in § 274.202(d)(2)(ii)(D)(II): if the sale of production from the subject reservoir (net of royalty) through any well that produced crude oil or natural gas in commercial quantities prior to April 20, 1977, at the *"market price reasonably available as of April 20, 1977"*, could not have generated revenues sufficient to equal or exceed the sum of 1.6 times the *"minimum incremental costs properly allocable to such production of installing cost-efficient facilities not in existence as of April 20, 1977"*, reasonably required to market such production, plus the *"minimum incremental expenses properly allocable to such production reasonably required to operate such facilities"*, then the Behind-the-Pipe Exclusion will not apply. (Emphasis added.) Application of the test requires the understanding of the following terms:

(1) The "market price reasonably available as of April 20, 1977" means the price reasonably likely to have been paid for the gas on that date. This might be shown, for example, by offers actually made to purchase the gas at a certain price or by the prices being paid for gas of similar quality on April 20, 1977, in the area of the sale.

(2) The phrase "minimum incremental costs" means the lowest additional capital costs, *i.e.*, non-recurring expenditures, for facilities.

(3) "Properly allocable to such production" means that if, for example, a gathering line would have been required to be built to gather the subject reserves but also would have been used to gather reserves known prior to April 20, 1977, and produced from other reservoirs through other wells, some reasonable allocation of the costs of that gathering line would have to be made. In addition, if oil or gas liquids (such as butane) would have been produced in conjunction with the subject reserves, then a reasonable allocation of costs to the separate products should also be made.

(4) "Cost-efficient facilities" means the most economical facilities reasonably required to sell the subject reserves. For example, if, all other things considered equal, the producer had the choice of building a 1 mile gathering line to sell the reserves to pipeline A or building a 20 mile gathering line to sell to pipeline B, the 1 mile line would probably be the "cost-efficient facility".

If the producer had the choice of installing a 4-inch gathering line and a 150 hp compressor or a 2-inch gathering line and a 50 hp compressor and the 2-inch gathering line and 50 hp compressor would have provided sufficient capacity for delivery, the 2-inch gathering line and 50 hp compressor probably would be the "cost-efficient facility." However, there may be cases where the cost-efficient facilities would have a capacity larger than that required to sell only the subject reserves. For example, if other reserves could have been attached to the same gathering line and other delivery facilities required to market the subject reserves, consideration of economies of scale might dictate considering the cost of facilities with a larger capacity and allocating such cost to the subject reserves on the basis of,

for example, the percentage of daily throughput through the system.

(5) The phrase "facilities not in existence as of April 20, 1977" means that only costs of additional facilities that were required to market gas but were not already installed as of April 20, 1977, are to be considered. For example, if a gathering line was already built as of April 20, 1977, none of the costs of that line would be considered in the test. If, however, the line was only partially completed and processing facilities were still required to be installed as of April 20, 1977, then the cost to complete the gathering line plus the cost to install the processing facilities would be considered. The "sunk costs" of that portion of the gathering facilities already installed as of April 20, 1977, would not be considered.

(6) The "minimum incremental expenses, properly allocable to such production, reasonably required to operate such facilities" means the lowest, most reasonable estimate of the total operating expenses, *i.e.*, recurring costs such as maintenance expenditures, that would be paid over time relative to producing and marketing reserves from the subject reservoir through the potentially disqualifying well. However, as in the case of capital costs, operating expenses must be allocated if the facilities used to market the subject reserves are also used to market other reserves. An example may clarify what is intended. Even though the capital costs invested in a gathering line in existence on April 20, 1977, are "sunk costs" and therefore irrelevant to the economic test, the expenses of operating that line incurred on or *after* April 20, 1977, are relevant. The total of those expenses should be subtracted from revenues in establishing whether the test is met. However, if the line would be used to gather other reserves in addition to the subject reserves, the total operating expenses must be allocated to the subject reserves on some reasonable basis; for example, the percentage of average throughput might be used for that purpose.

We have formulated two examples located in Appendix B to this order to further clarify how the economic test should be applied in practice.

We believe that this economic test accomplishes the congressional intent of section 102 of the NGPA. Not only did Congress wish to encourage the production of previously non-commercial reserves by allowing an incentive price but Congress also wished to deny this incentive price to production withheld from the marketplace for purposes of price speculation, *i.e.*, cases where an incentive price should not be necessary to encourage production of the reserves. This intent underlies the Behind-the-Pipe and Withheld Gas Exclusions. The Commission believes that the economic test adopted herein for the Behind-the-Pipe Exclusion will encourage production of reserves which were not commercial prior to April 20, 1977; *i.e.*, reserves the sale of which could not generate revenues at least equal to the incremental costs and expenses of marketing the gas plus a minimum reasonable return. Furthermore, the Commission believes an economic test which would allow a return higher than such minimum return as well as a recovery of sunk costs would contravene the intent underlying the Behind-the-Pipe Exclusion because it might permit the section 102 maximum lawful price to be applied to gas previously withheld from production in order to speculate on greater profits than could have been generated if the reserves had been sold at prices available on April 20, 1977.

The test employs factors used in making the common business decision of whether to expend additional money on a given project or to apply it elsewhere. Only incremental expenditures and incremental revenues are relevant in deciding whether to expand additional money on the project.

Expenditures incurred prior to the date of the decision are irrelevant to that decision. The economic test for the

Behind-the-Pipe Exclusion fixes that decisional date as April 20, 1977. Consequently, the only costs to be considered are those incremental costs which were necessary as of April 20, 1977, in order to produce natural gas from the reservoir in commercial quantities.

B. Section 271.204(c)—Definition of "Commercially Producible" as Used in Section 102(d) of the NGPA

Section 271.204(c) of the Commission's Regulations defines the term "commercially producible" which is found in section 102(d)(2)(B)(iii) of the NGPA. Section 102(d) of the NGPA generally provides that gas produced from old OCS leases from reservoirs discovered on or after July 27, 1976, may qualify for the section 102 price. A reservoir will be considered as having been discoverd before July 27, 1976, if it was penetrated by a well prior to July 27, 1976, and the results of at least one of three possible groups of tests (described in section 102(d)(2)(B)) demonstrate that production from the reservoir was potentially economic as of the time of the tests. If a production test, or production capability evidence, meeting the requirements of OCS Order No. 4, demonstrates that the well was "capable of producing in paying quantities," the reservoir is disqualified. If induction-electric logs, sidewall cores and other test data indicate that, at the time of the test, the reservoir was "commercially producible," then, again, the reservoir is disqualified.

Section 271.204(b) defines "capable of producing in paying quantities" in terms of whether the eventual sale of the reserves would have generated sufficient revenues to recover out-of-pocket operating costs. This is the standard consistently applied by the United States Geological Survey (USGS). However, § 271.204(c) ties the definition of "commercially producible" to the definition of "production in commercial quantities" which is based on whether there have been actual sales and deliveries or the gas has been retained for beneficial economic use.

One Petitioner suggests that the definition of "commercially producible" should not be linked to the definition of "production in commercial quantities" in § 270.102(b)(4). Upon reconsideration of this issue, we agree. The term "commercially producible" in clause (iii) of NGPA section 102(d)(2)(B) is actually linked to the same types of tests and evidence that are the subject of the paying quantities standard in clauses (i) and (ii) of section 102(d)(2)(B). All three clauses are designed to determine if a reservoir was discovered prior to July 27, 1976. We do not believe that one economic test should be applied to determine the capability of a reservoir to produce in paying quantities, and another to determine if the same reservoir would be commercially producible if both are to be used to determine the same thing—the date of discovery of the reservoir. Accordingly, we shall amend § 271.204(c) to require the same out-of-pocket cost test for the commercially producible standard which we applied in § 271.204(b) for the paying quantities standard. We also have amended the reporting requirements at § 274.203(e)(3) to refer to "commercially producible."

One Petitioner and Indicated Producers assert that § 271.204(c) ignores when the determination of "commercially producible" is to be made, *i.e.,* when the results of such tests became available. They suggest that § 271.204(c) should be amended so that an economic test is based on the tests and evidence available before July 27, 1976, and that the economic test itself should take into account all costs which would have been required to be incurred after the date of such tests to produce and market the gas, including, for example, the costs of additional platforms and pipelines.

We disagree with the Indicated Producers suggestions, and therefore shall deny Indicated Producers' Motion for Reconsideration. First, the § 271.204(c) definition of "commercially producible" does not eliminate the requirement otherwise found in the third clause of section 102(d)(2)(B) that the "commercially producible" determination is to be made as of the time the tests were made or evidence was obtained. Second, as to the issue of the type of economic test to be applied, we believe Congress clearly intended to adopt the criteria by which the USGS makes an OCS reservoir determination. Those criteria include the application of the out-of-pocket cost analysis already described in § 271.204(b).[13]

C. Notice

One Petitioner asserts that the Commission failed to give adequate notice and opportunity to participate in Docket No. RM79-68 because its Final Regulations issued in Order No. 42 go beyond mere clarification or interpretation of the Behind-the-Pipe Exclusion.

We disagree. First, Order No. 42 was the culmination of a rulemaking process involving the issuance of interim regulations on December 1, 1979, followed by public hearings and a lengthy comment period ending January 29, 1979. During that comment period the proper interpretation of all parts of section 102 was raised for public comment and the Petitioner had adequate opportuntiy to recommend as it now suggests, that an economic test should be applied with respect to the Behind-the-Pipe Exclusion. Moreover, Petitioner's claim is moot because under this order we have promulgated an economic test for the phrase "could have been produced in commercial quantities", in the Behind-the-Pipe Exclusion. This was what the Petitioner had requested.

D. Section 102(c)(1)(B)—New Onshore Wells

One Petitioner suggests that we erred in our answer to a question involving new recompletions by restricting the application of the section 102 price to only gas produced from "new wells." In Order No. 42, we stated:

> Another comment suggested that new recompletions, either by plug back or re-entry, should qualify for the section 102 price. Although it is more economical in some instances to recompete a well than to drill a new well, the statutory language limits the section 102 price, *inter alia*, to wells spudded on or after February 19, 1977 or wells drilled to an increased depth of at least 1000 feet on or after February 19, 1977. [Mimeo at page 3]

We did not intend this statement to be read as requiring the drilling of a "new well" in order to qualify gas from a new OCS lease, a new onshore reservoir, or a new OCS reservoir on old OCS lease for the section 102 price. A well must be a "new well" only if its is to qualify as a "new onshore well" under section 102(c)(1)(B).

III. Public Procedures and Effective Dates

For the reasons discussed in Order No. 42 (issued August 14, 1979), the amendments to § 271.204(a) and (b) of Subpart B of Part 271 were issued as final regulations and were immediately effective as to jurisdictional agency determinations which had not become final (as determined in § 275.202) as of August 13, 1979.

Our order today: amends paragraph (c) and adds a new paragraph (f) to § 271.204; makes several changes to the interim regulations in § 274.202; and makes a conforming amendment to the interim regulations in § 274.203(e)(3).

The amendment to paragraph (c) of § 271.204 and the conforming modification to § 274.203(e)(3), were made in response to comments made in Indicated Producer's motion for reconsideration as well as the petitions for rehearing of Order No. 42. The effect of the amendments is to conform our regulations to existing USGS standards of review. Accordingly, it is in the public interest to issue the amendments to the final regulations in § 271.204(c) and the interim regulations in § 274.203(e)(3) effective immediately with regard to jurisdictional agency determinations which have not become final under § 275.202 as of the day before the date of issuance of this order.

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[13] See the public file on Docket No. RM79-68.

The amendments which apply a new economic test to determinations which involve the Behind-the-Pipe Exclusion (and associated reporting requirements), were made in response to comments we have received to date. We shall therefore issue these as final regulations and shall not request further public comments. We believe that complying with the 30-day publication requirement of section 553(d) of the Administrative Procedure Act is impractical in this case and contrary to the public interest since numerous jurisdicational agency determinations dealing with the Behind-the-Pipe Exclusion are pending and uncertainty exists respecting the application of the Behind-the-Pipe Exclusion. Therefore, new paragrph (f) in § 271.204 is issued as a final rule and new clauses (C) and (D) of § 274.202(d)(2)(ii) are issued as interim rules, effective immediately for all applications for which a jurisdictional agency determination has not been made as of the day before the date of issuance of this order. In the case of determinations already received by the Commission for which the 45 day period under § 275.202(a) has not expired, or if applicable, the 120 day period under § 275.202(e), we shall provide applicants the opportunity to supplement their applications in accordance with the amended regulations, in which case we may remand the determinations to the jurisdictional agencies for their reconsideration.

The Commission orders:

(A) The Petitions for Rehearing reference above filed in Docket No. RM79–68 are granted in part and denied in part as is more fully detailed in the text above.

(b) The motion for reconsideration filed by Indicated Producers is denied.

(c) Parts 271 and 274 of the Commission's regulations are amended as set forth below to be effective as set forth above.

(Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.*; Department of Energy Organization Act, 42 U.S.C. 7107, *et seq.*; E.O. 12009, 42 F.R. 46267; Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301–3432.)

In consideration of the foregoing, the final rules in Part 271 and the interim rules in Part 274 of Subchapter H, Chapter I, Title 18, Code of Federal Regulations are amended as set forth below, effective as set forth above.

By the Commission.

Kenneth F. Plumb,
Secretary.

Appendix A

The Commission has established a rule-of-thumb formula which employs a 1.6 multiplier in all cases as a surrogate for a more detailed return analysis conducted on a case-by-case basis. Such case-by-case analyses would create too great an administrative burden to be feasible. The constant of 1.6 was derived from an average annual investment analysis which assumed an investment of $500,000, a Federal income tax (FIT) rate of 48 percent [1] and a required after-tax rate of return of 6.25 percent. The analysis also employed a 15-year depletion period as well as the sum-of-the-year digits method of depreciation. Fifteen years was chosen as a reasonable approximation of the average depletion period, based on the depletion period used in Opinion No. 770.[2]

The sum-of-the-years digits method of depreciation was used because the Commission believes that it best approximates the results of the unit of production method of depreciation employed in industry. That method is representative of actual delivery from a reservoir. Normally, the reservoir is produced at a high rate in early years and declines in production on an exponential basis in later years.

The result of the analysis indicates that the resulting amount of return and FIT is $310,496, approximately 60 percent of the assumed investment of $500,000. Therefore, in the average case, increasing the incremental costs by 60 percent (*i.e.,* multiplying by a constant of 1.6) will produce an after-tax return of approximately 6.25 percent.

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[1] State income taxes were not provided for because of differing tax structures in the various states.

[2] *Mimeo.* at page 68 (issued July 27, 1976 in Docket No. RM75–14).

Calculation of Return Allowance and Federal Income Taxes

Assumptions

1. 15 year productive life.
2. After tax return allowance: 6.25%.
3. 1977 statutory tax rate: 48%.
4. Employed sum-of-the-year digits method of depreciation.
5. No salvage value.
6. Estimated incremental capital costs: $500,000.

	Beginning of year investment	Depreciation	End of year investment	Average investment
Year:				
1	$500,000	$62,500	$437,500	$468,750
2	437,500	58,333	379,167	408,334
3	379,167	54,167	325,000	352,083
4	325,000	50,000	275,000	300,000
5	275,000	45,833	229,167	252,084
6	229,167	41,667	187,500	208,334
7	187,500	37,500	150,000	168,750
8	150,000	33,333	116,667	133,334
9	116,667	29,167	87,500	102,083
10	87,500	25,000	62,500	75,000
11	62,500	20,833	41,667	52,084
12	41,667	16,667	25,000	33,333
13	25,000	12,500	12,500	18,750
14	12,500	8,333	4,167	8,334
15	4,167	4,167	0	2,083
Totals		500,000		2,583,336

Average Annual Investment=$2,583,336 ÷ 15 years=$172,222.
Return Allowance=($172,222×0.0625)×15 years=$161,458.
Federal Income Taxes=$161,458×.48/52=$148,038.

Return plus Federal Income Tax ($310,496) is approximately 0.62 times the initial investment.

Appendix B

Two examples should help clarify how the test is to be applied.

Hypothetical No. 1—Assume that, as of April 20, 1977, the applicant was flaring casinghead gas produced in conjunction with commercial oil production through an old well (subject well) from the subject reservoir. Gas was flared due to the absence of a required gas gathering line as of that date. Several months later, the producer builds the gathering line and commences sales and deliveries of the casinghead gas produced from the subject reservoir through the subject well (subject reserves) as well as gas he produced from other wells in the same locality as the subject well using the newly built gathering line. Assume that the record reflects that the most economical gathering system would be comprised of a 4-inch line and a 150 hp compressor capable of efficiently handling the throughput from all wells in the same locality rather than a 2-inch line and 50 hp compressor that would have been required to carry only the subject reserves. Also assume that the record reflects that, as of April 20, 1977, the producer had the choice of (1) building a 1-mile long, 4-inch gathering line at a total capital cost of $40,000 plus $10,000 total estimated future operating expenses to sell the subject reserves to pipeline A and receive $1.45 per Mcf for the gas, or (2) to build a 20-mile long, 4-inch gathering pipe at a total capital cost of $500,000 plus $75,000 total estimated future operating expenses to sell to pipeline B and receive the same $1.45 price. Assume 50,000 Mcf [1] of "subject reserves" producible through the subject old well based on the producing history of the reservoir and another 50,000 Mcf of other reserves know to exist as of April 20, 1977, that would be expected to be attached to the same gathering line.

Clearly the facilities in the first alternative would involve the most economical, and therefore "cost-efficient", facilities for marketing the subject reserves given that in both alternatives the gas will receive the same price. Fewer facilities at a lower total cost are involved. The economic test would, therefore, focus on the first alternative. At that point in the inquiry any reasonable method of allocating the costs and expenses to the subject reserves could be applied. For example, the ratio of subject reserves to total reserves or the ratio of daily throughput could be used to allocate costs and expenses. Assume that the record reflects a reasonable allocation procedure that results in $20,000 capital costs and $5,000 operating expenses allocable to the subject reserves.

The test, as described in § 271.204(f)(1) and § 274.202(d)(2)(ii)(D)(II) using a formula format, is applied as follows: [[market price available on April 20, 1977) × (total reserves net of royalty producible through the subject well from the subject reservoir in Mcf)] − [((1.6) × ("the minimum incremental costs, properly allocable to such production, of installing cost-efficient facilities not in existence as of April 20, 1977, reasonably required to market such production")) + ("the minimum incremental expenses, properly allocable to such production, reasonably required to operate such facilities")]. If the result is negative, then the exclusion does not apply.

Inserting the data of the correct hypothetical facilities into the formula, produces the following results:

[($1.45/Mcf) × (50,000 Mcf)] − [((1.6) × ($20,000)) + ($5,000)] = [$72,500] − [$37,000] = $35,500

Because the project could have recovered more than the required costs, expenses and return, the "could have been produced in commercial quantities" test is met, the Behind-the-Pipe Exclusion applies, and the reservoir is disqualified as a new onshore reservoir.

Hypothetical #2—Assume that, as of April 20, 1977, an old gas well (subject well) was producing gas from a lower zone, which gas was being sold, and the upper "Behind-the-Pipe" zone (the subject reservoir) was in a non-producing status at that time. The record reflects that the estimated cost to recomplete into the subject reservoir at such later time as the lower zone is depleted would be $2,000 when estimated as of April 20, 1977. Future total operating expenses properly allocable to the subject reserves are estimated to be $5,000. The market price, as of April 20, 1977, was $1.45 (based on the price being received for production from the lower zone) and 50,000 Mcf [2] of reserves were estimated to be producible from the subject reservoir through the subject well (subject reserves). However, the applicant also submits evidence that the gathering system used to market the gas from the subject well was built at a cost of $150,000 in 1976. He also offers proof that the cost of a new well to commence actual production and sales from the subject reservoir prior to April 20, 1977 would have been in excess of $100,000.

The record facts should be analyzed as follows. The only capital cost relevant for consideration is the $2,000 cost of a prospective recompletion. The $150,000 expenditure was a sunk cost as of April 20, 1977. That expenditure is irrelevant to the economic considerations facing the producer on April 20, 1977, *i.e.*, whether the price he could receive for producing the subject reserves would make it worth his spending an additional $2,000 to recomplete into that zone sometime in the near future. The $100,000 estimated cost of a new well is also irrelevant because the test concerns only the commerciality of producing gas from the subject reservoir *through the subject old well* assuming that, *when the zone is eventually completed in*, the price would be limited to the market price available on April 20, 1977. The test does not inquire into alternative ways of commencing actual production and sales prior to April 20, 1977.[3] Accordingly, only $2,000 of additional costs would be required to commence sales of gas produced from the subject reservoir *through the subject old well.* The formula would be applied as follows:

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[1] Measured at 14.73 psia, 60° F. and BTU content of 1,000 Btu/cf.

[2] Measured at 16.73 psia, 60° F. and a Btu content of 1000 Btu/cf.

[3] As we noted earlier, the physical capability aspect of the "could have been produced in commercial quantities" test only relates to the physical capability of the reservoir to produce if and when it is completed in and all sale facilities are in place.

$$[(\$1.45/\text{Mcf}) \times (50{,}000\ \text{Mcf})] - [((1.6) \times (\$2{,}000)) + (\$5{,}000)] = [\$72{,}500] - [\$8{,}200] = \$64{,}300$$

Again, because the applicant could have recovered the required costs, expenses and return, his reservoir is disqualified.

[¶ 30,110]

44 F. R. 69935 (December 5, 1979)

18 CFR Parts 2 and 271

[Docket No. RM79-19; RM78-12]

Order Granting Rehearing for the Purpose of Further Consideration and Further Staying of Order No. 45 and Order No. 31-A

Issued November 30, 1979.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Order Staying Effective Date.

SUMMARY: On October 19, 1978 the Commission stayed the effective date of Orders 45 (Docket No. RM79-19) and 31-A (Docket No. RM78-12) until December 5, 1979 [44 FR 61327, October 25, 1979]. Order No. 45 [44 FR 51554, September 4, 1979] addressed the issue of producer responsibility for production-related costs incurred in first sales of natural gas produced at Prudhoe Bay, Alaska for transport through the Alaska Natural Gas Transportation System by amending Commission regulations under the Natural Gas Policy Act and providing a policy statement under the Natural Gas Act. Order No. 31-A [44 FR 41681, September 4, 1979] implemented the policy of Order No. 45. Petitions to rehear both orders were received. In addition, the Secretary of Energy requested rehearing to permit time for certain actions by the Department of Energy which will relate to Order No. 45. In light of these requests, and because of the complexity of the issues involved it is appropriate to further stay the effective date for both orders.

DATE: Effective dates of Order No. 45 and Order No. 31-A stayed until December 21, 1979.

FOR FURTHER INFORMATION CONTACT: John Conway, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8100-K, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357-8150.

Before Commissioners: Charles B. Curtis, Chairman; Georgiana Sheldon, Matthew Holden, Jr., and George R. Hall.

In the matter of treatment of certain production-related costs for natural gas to be sold and transported through the Alaska natural gas transportation system, Docket No. RM79-19; and determination of incentive rate of return, tariff and related issues, Docket No. RM78-12. Order Granting Rehearing for the Purpose of Further Consideration and Further Staying of Order No. 45 and Order No. 31-A.

On August 24, 1979, the Commission issued final regulations respecting the treatment of production-related costs under the Natural Gas Policy Act for natural gas produced at Prudhoe Bay Alaska for transport through the Alaska Natural Gas Transportation System (ANGTS). These were issued as Order No. 45 in Docket No. RM79-19. On the same day the Commission issued Order No. 31-A in Docket No. RM78-12 which applied the policy of Order 45. On September 21, 1979, the Atlantic Richfield Company, the Sohio Natural Resources Company, and the Phillips Petroleum Company filed separate applications for rehearing of these two orders. On September 24, 1979, the State of Alaska and the Exxon Corporation filed separate applications for rehearing of the two orders. On October 15, 1979, the Commision was informed by letter from the Secretary of Energy that a formal filing by the Department of Energy will be made which will reflect discussions held by the Department and

North Slope producers on the impact of producer financing commitments for the ANGTS on Order 45. The Secretary's letter therefore requested rehearing to reconsider Order No. 45.

On October 18, 1979, the Commission granted rehearing of Order No. 45 and Order No. 31-A solely for purposes of further consideration. This was done in response to the request of the Secretary of Energy and to conclude deliberations of the issues raised in the applications for rehearing. In that order the Commission found that it was appropriate to stay the effective date of Order No. 45 and Order No. 31-A until a fixed date, December 5, 1979. Due to the complexity of the issues involved, and in the absence of any further filing by the Department of Energy, it is appropriate to extend that stay until December 21, 1979.[1]

The Commission orders:

(A) The petitions for rehearing of Order No. 45 and Order No. 31-A, filed in this proceeding, are granted solely for the purpose of affording further time for consideration of the petitions and to afford further time for relevant filings on the part of the Department of Energy. This action does not constitute a grant or denial of the petitions on their merits in whole or in part. As provided by § 1.34(d) of the Commission's Regulations, no answer to the applications filed in this proceeding will be entertained by the Commission since this order does not grant rehearing on any substantive issues.

(B) Ordering Paragraph (1) of Order No. 45, issued August 24, 1979, under Docket No. RM79-19 and Ordering Paragraph (B) of Order No. 31-A, issued August 24, 1979, under Docket No. RM78-12 are stayed until December 21, 1979.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,111]

44 F. R. 71821 (December 12, 1979)

18 CFR Part 2

[Docket No. RM79-25]

Electric Utility Reporting on Measures To Implement Conservation of Natural Resources

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission hereby revokes its voluntary annual reporting procedures concerning the conservation activities of electric utilities. These procedures are no longer a cost effective effort in the public interest.

EFFECTIVE DATE: Effective January 1, 1980.

FOR FURTHER INFORMATION CONTACT: Bernard Chew, Office of Electric Power Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 376-9284 or Christine P. Benagh, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8033.

December 6, 1979.

Background

This order amends the Federal Energy Regulatory Commission's (Commission) general rules by revoking § 2.14. Section 2.14 was established pursuant to the authority of section 202(a) of the Federal Power Act, as amended, 49 Stat. 848, 16 U.S.C. 824(a). The provisions of § 2.14 instituted a voluntary procedure under which electric utilities reported with respect to their conservation activities. This procedure was intended to facilitate government and public awareness of such activities and to promote the conservation and effective use of natural resources in electric power production.

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[1] As with the initial stay of October 18, 1979, this order does not apply to Order No. 31 or Order No. 31-B, issued under Docket No. RM78-12. Orders 31 and 31-B are formal orders now in effect.

In March of this year, however, in view of the greatly expanded scope of Federal and State programs to promote energy conservation, the Commission suggested *via* a Notice of Proposed Rulemaking that the continued reporting of this generalized information might not any longer represent a cost-effective effort in the public interest.

Summary of Comments

The referenced Notice of Proposed Rulemaking was issued on March 22, 1979 (44 FR 2274, April 17, 1979). Eleven parties responded to the Notice. The eleven utilities which responded to the Notice argued that revocation of § 2.14 would be in the public interest.

Niagara-Mohawk Power Company stated that the same information is reported to the New York Energy Office, to the New York Public Service Commission as part of rate cases, and to the Electric Power Research Institute where it is catalogued and made available to the public. Georgia Power Company stated that the § 2.14 reports are redundant because of other reports required by other agencies. Consolidated Edison Company of New York noted its belief that reports filed under this section were not susceptible to use as a basis for Commission findings.

Effective Date

This rule is to be effective January 1, 1980.

(Federal Power Act, as amended, 16 U.S.C. 792–828c; Department of Energy Organization Act, 40 U.S.C. 7101–7352; E.O. 12009, 42 FR 46267)

In consideration of the foregoing, Part 2, Subchapter A of Chapter I, Title 18, Code of Federal Regulations is hereby amended as set forth below, effective January 1, 1980.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,112]

44 F. R. 76482 (December 27, 1979)

18 CFR Parts 2 and 271

[Docket Nos. RM79–19 and RM78–12; Orders Nos. 45 and 31–A]

Order Granting Rehearing for the Purpose of Further Consideration and Further Staying of Order No. 45 and Order No. 31–A

December 20, 1979.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Order Staying Effective Dates.

SUMMARY: On August 24, 1979 the Commission issued Order No. 45 (Docket No. RM79–19) and Order No. 31–A (Docket No. RM78–12) [44 FR 51554, 41681, September 4, 1979]. By these orders the Commission amended regulations issued under the Natural Gas Policy Act and implemented a policy under the Natural Gas Act so that responsibility for production-related costs incurred in first sales of natural gas produced at Prudhoe Bay, Alaska for transport through the Alaska Natural Gas Transportation System could be addressed. Petitions to rehear both orders have been received and, in addition, the Secretary of Energy has requested a stay of the effective dates of the two orders to permit time for filing by him of certain data. For these reasons the Commission stays the effective date of the two orders until further notice by the Commission.

DATE: Effective dates of Order No. 45 and Order No. 31–A stayed until further notice by the Commission.

FOR FURTHER INFORMATION CONTACT: John Conway, Office of the General Counsel, Federal Energy Regulatory Commission, Room 6100–K, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357–8150.

Before Commissioners: Charles B. Curtis, Chairman; Georgiana Sheldon, Matthew Holden, Jr., and George R. Hall.

In the matter of treatment of certain production-related costs of natural gas to be sold and transported through the Alaska Natural Gas Transportation System, Docket No. RM79-19; and determination of incentive rate of return, tariff and related issues, Docket No. RM78-12.

On August 24, 1979, the Commission issued Order No. 45 under Docket No. RM79-19 (44 FR 51554, September 4, 1979). That order established regulations respecting the treatment of production-related costs under the Natural Gas Policy Act for natural gas produced at Prudhoe Bay, Alaska for transport through the Alaska Natural Gas Transportation System (ANGTS). At the same time, the Commission issued an order which applied the policy of Order No. 45. This latter order, Order No. 31-A, was issued under Docket No. RM78-12 (44 FR 51681, September 4, 1979). Applications to rehear both of those orders were filed. [1] In addition, the Commission was informed by letter from the Secretary of Energy dated October 15, 1979, that a formal filing would be made by the Department of Energy under Docket No. RM79-19. That filing would reflect discussions held by the Department and North Slope producers of producer financing commitments for the ANGTS and the impact of such commitments on Order No. 45. In light of both the petitions to rehear and the offer of the Department of Energy to make a filing in this matter, the Commission granted limited rehearing for Orders 45 and 31-A and stayed the effective date of those two orders until December 21, 1979. [2]

On December 5, 1979, the Commission was notified by letter from the Secretary of Energy that discussions with the North Slope producers concerning financing for the ANGTS are continuing. In that letter, the Secretary requested that, because of the complexity of the undertaking and the need for additional negotiations, the time to rehear Order No. 45 should be extended until such time as the Secretary can definitively report on the outcome of his discussions with North Slope producers. Accordingly, the Commission finds that it is appropriate to further stay the effective date of Order No. 45 and Order No. 31-A [3] to permit the Secretary of Energy the opportunity to intervene in the proceedings and to make such filings as he may deem appropriate.

The Commission Orders: (A) The petitions for rehearing of Order No. 45 and Order No. 31-A, filed in this proceeding, are granted solely for the purpose of affording further time for consideration of the petitions and to afford further time for relevant filings on the part of the Department of Energy. This action does not constitute a grant of denial of the petitions on their merits in whole or in part. As provided by § 1.34(d) of the Commission's Regulations, no answer to the applications filed in this proceeding will be entertained by the Commission since this order does not grant rehearing on any substantive issues.

(B) Ordering Paragraph (1) of Order No. 45, issued August 24, 1979, under Docket No. RM79-19 and Ordering Paragraph (B) of Order No. 31-A, issued August 24, 1979, under Docket No. RM78-12 are stayed until further notice of the Commission.

By the Commission.

Kenneth F. Plumb,
Secretary.

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[1] On September 21, 1979, the Atlantic Richfield Company, the Sohio Natural Resources Company, and the Phillips Petroleum Company filed separate applications for rehearing of these two orders. On September 24, 1979, the State of Alaska and the Exxon Corporation filed separate applications for rehearing of these two orders.

[2] Order Granting Rehearing for the Purpose of Further Consideration and Staying of Order No. 45 and Order No. 31-A, issued October 19, 1979 (44 *Fed. Reg.* 61327 October 25, 1979); Order Granting Rehearing for the Purpose of Further Consideration and Further Staying of Order No. 45 and Order No. 31-A, issued November 30, 1979 (44 *Fed. Reg.* 69935, December 5, 1979).

[3] As with prior stays, this order does not apply to Order No. 31 or Order No. 31-B, issued under Docket No. RM78-12. Order Nos. 31 and 31-B are final orders now in effect.

Regulations Preambles

45 Federal Register (1980)

[¶ 30,113]

45 F. R. 21 (January 2, 1980)

18 CFR Part 282

[Docket No. RM80-16]

Disclosed Estimation Methodology Approach for Determination of Volumes of Natural Gas Used for Exempt Purposes Under the Incremental Pricing Program; Interim Rule

Issued: December 27, 1979.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Interim rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) hereby issues an interim rule which establishes procedures to be used for the first ten months of the incremental pricing program by industrial users in calculating the volumes of natural gas subject to incremental pricing surcharges. The Commission solicits comments on this interim rule and intends to hold a public hearing with respect to this matter. The date and location of the hearing will be announced at a later date.

DATES: Effective December 27, 1979. Comments due February 1, 1980. Date of public hearing to be announced later.

ADDRESS: All comments to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426 (Reference Docket No. RM80-16). Hearing location: to be announced.

FOR FURTHER INFORMATION CONTACT: Barbara K. Christin, Office of the General Counsel, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8079.

I. Background

The Commission hereby issues an interim rule which establishes procedures to be employed for the first ten months of the incremental pricing program by industrial users in calculating the volumes of natural gas subject to incremental pricing surcharges.

On September 28, 1979, the Federal Regulatory Commission (Commission) issued final regulations in Docket No. RM79-14 to implement portions of the first phase of the incremental pricing program under the Natural Gas Policy Act of 1978 (44 FR 57725, October 5, 1979).

The regulations in Docket No. RM79-14 contain the provisions for the calculation of the incremental pricing surcharge to be billed to each industrial facility covered by the regulations. One step necessary to calculate this surcharge is the determination of the volumes of natural gas consumed in a facility for uses which are subject to being incrementally priced.

In the preamble to the September 28th final rule the Commission stated that it had determined to require the installation of submeters within those industrial facilities which consumed natural gas for both exempt and non-exempt uses. This requirement will become effective on November 1, 1980. In the interim period from January 1, 1980 (the date on which the incremental pricing program will be activated), through October 31, 1980, the Commission determined to accept either certified estimates, or an agreement between a natural gas supplier and a customer, as to the volume of natural gas used in a facility for exempt purposes.

A technical conference was held in Chicago, Illinois, on November 15-16, 1979, in order to discuss how the certified estimates to be utilized for the first ten months of the incremental pricing program could be standardized. In the notice calling the conference (44 FR 61174, October 24, 1979), the Commission Staff (Staff) identified several methods which could be utilized for preparing estimates and solicited comments on those methods. In addition, the Staff invited parties who would be preparing such estimates to describe in detail their intended approach, and to furnish examples for Staff analysis.

Representatives of industrial end users, local distribution companies, associations representing local distribution companies and industrial end users, and meter manufacturers made formal presentations and later participated in informal discussions at the technical conference.

The comments submitted at the technical conference and inresponse to the notice of the conference proved very helpful to the Commission. The Commission notes that the disclosed methodology approach contained in the interim regulations set forth below is, in large part, the result of the record established at and as a result of the conference.

II. Comments on Standardized Procedures

As has been noted above, the notice calling the technical conference stressed the Commission's desire to develop standardized estimation methodologies, and requested comments on estimating procedures with the goal of standardization in mind.

The comments received at the technical conference were generally critical of standardized estimates. Industry representatives repeatedly stressed the great diversity of industrial facilities and the variety of estimation techniques currently used by industry to calculate its energy, including gas, consumption.

The steel industry was put forward as an example of industrial diversity. Industrial representatives explained that a typical, integrated steel mill utilizes a mixture of fuel gases—natural gas, coke oven gas, and blast furnace gas—for a variety of end uses. The ratio of gases in the mixed stream was said to vary both over time and with location in the facility. Since a number of gas-fired pieces of equipment draw from the mixed stream at various locations, a general rule specifying the fraction of natural gas to each end use was alleged to be infeasible. In addition, there is an added variable in some steel mills of a mixed steam output from a single boiler. Steam from such a boiler is delivered to both non-exempt uses and exempt uses, such as cogeneration.

Based upon the comments submitted, every steel mill appears to represent a unique spatial distribution of end uses, served by a unique piping arrangement. The extent of existing metering, of both gas and steam, also differs from plant to plant. Nevertheless, industry representatives were confident that they would be able to develop, based upon objective data, reliable estimates as to the gas usage which would be subject to incremental surcharges.

The agricultural sector presented a similar picture of industrial diversity. The typical estimation problem in the agricultural sector is not the mixed gas stream, but the mixed product situation. In one variation, steam from a single boiler or steam header is routed to a number of uses, some agricultural, some not. In another variation, a given product may be used for both agricultural and non-agricultural uses. Again, the degree of existing submetering (for either gas or steam) varies widely. It was argued that no general rule would be appropriate for all facilities.

III. Disclosed Estimation Methodology Approach

Several commenters who either participated at the technical conference or later submitted written comments suggested that the Commission adopt a so-called "disclosed estimation methodology" approach in lieu of standardized estimating procedures. The Commission has been persuaded on the basis of the comments submitted in connection with the technical conference that the disclosed estimation methodology approach will prove to be more feasible than would standardized procedures.

Thus, the interim rule below sets forth the regulatory provisions needed to implement the disclosed methodology approach. In addition to provisions which will govern the administrative aspects of the approach—*i.e.*, filing requirements, *etc.*—the interim rule contains provisions which will govern how estimates should be determined in certain situations. Specifically, the rule provides for the treatment of: natural gas used for space heating, natural gas used in situations where a portion of the product or products manufactured is eligible for an exemption, and self-help supplies of natural gas which are commingled with utility-supplied gas.

Under the disclosed methodology approach those industrial users, only a portion of whose natural gas usage is subject to incremental pricing surcharges, will be required to formulate and file an estimation methodology with the Commission, the user's natural gas supplier, and the State or local regulatory authority having jurisdiction over the natural gas service provided to the user.

The methodology must be based on techniques which are in accordance with sound engineering practices. It is expected that a responsible individual familiar with plant operations, most probably but not necessarily an engineer, will formulate the estimating methodology to be used.

Under the rule, the methodology must be filed on a one-time basis. Thereafter, each month the industrial user will notify his supplier of his exempt usage by means of an affidavit which sets forth the actual calculations which are based upon the disclosed methodology.

The regulations are purposely general and do not attempt to specify a methodology for all situations. The Commission recognizes the likelihood that, for any estimation procedure, some industrial facility exists for which the procedure would be unworkable. Furthermore, no method is likely to be optimum for all cases.

A. Estimation Methodology

The estimation methodology should be precisely stated, so that any technically knowledgeable individual working with the same input data would reach similar results. Any "rule of thumb" must be verifiable.

The interim regulations contain several prorating requirements, which are set forth in § 282.207(c). Staff has received a number of requests for guidance in the treatment of the portion of natural gas which is used to raise steam for space heating within a facility which uses natural gas as a boiler fuel for both exempt and non-exempt uses. This question has predominantly arisen in situations relating to agricultural facilities. In some cases, all the steam is utilized for an exempt agricultural use except that portion used for space heating within the facility.

In a mixed product situation, in addition to the steam being used for both exempt and non-exempt end products, a portion of the steam is also used for space heating purposes. Since some space heating in an agricultural facility is most likely needed for product quality maintenance, the natural gas used to raise the steam for such a purpose would qualify as an exempt use.

The Commission believes that it would be administratively infeasible to require that industrial users trace each use of space heat to determine those uses which would be exempt. Therefore, the Commission provides, in § 282.207(c)(1), that the natural gas used for space heating by an industrial facility is exempt from incremental pricing in the same proportion that the gas used as a boiler fuel for other purposes is exempt.

Section 282.207(c)(2) requires that, in a mixed product situation, only that portion of the natural gas consumed, directly or indirectly, for the manufacture of exempt products shall be exempt from incremental pricing surcharges. In the case of textile mills, which process or produce a product that is a combination of natural and synthetic fibers, the rule requires a proration of the use of natural gas between natural fiber production or processing and synthetic fiber production or processing, such that an appropriate portion of the natural gas is exempt. The determination of the appropriate portion shall be based on physical data relating to the fraction of mixed fiber that is natural. Any other considerations shall be specified and be subject to verification.

In a mixed product situation where uncertainty exists at the time of production concerning the status of an end product as exempt or non-exempt, the estimating methodology should clearly state that an "indeterminant product" situation exists. Estimates may be based on past experience or expressed buyer intentions, but to the extent that subsequent events prove the estimates incorrect, the error must be compensated for in future estimates.

The Commission is especialy concerned with situations in which it is physically impossible to trace the flow of energy deriving from natural gas to either exempt or nonexempt end uses. There are a number of circumstances in which this situation will arise. The mixed gas stream which feeds multiple end uses is one; the common steam header supplied with steam from differently fueled boilers and serving multiple steam requirements is another.

While the Commission is not requiring that such indeterminate situations be resolved only by prorating natural gas input by the fraction of total energy consumed in exempt and non-exempt end uses, any user who wishes to depart from such a prorating approach and assign natural gas volumes to specific end uses should be prepared to defend his methodology with actual data relating to plant operations. Unfounded assumptions that certain fuels and end uses are "at the margin" will not meet the requirement of reliance on sound engineering practice.

Section 282.207(c)(3) sets out the Commission's position on the prorating, among various end uses, of an industrial consumer's self-help gas supplies which are commingled with utility-supplied natural gas. The user is not given the discretion to designate the self-help gas to certain non-exempt end uses, unless such designation can be supported by plant operating data in the same manner as any other designation of fuels to end uses which is made in accordance with these regulations.

B. Monthly Estimates

The Commission stresses that all estimates must be based upon objective, measurable data. An estimate may rely upon existing in plant metering (such meters need not necessarily meet utility standards.) Steam meters may be used where gas metering is absent or unworkable. If no form of metering is available, production records should form the basis of the estimates. Although any number of data can be taken into account, such data must be quantitative and auditable.

If estimates of boiler efficiency are employed in the estimating procedure, the end user should be prepared to produce the efficiency estimate and the means employed to develop it, upon request, in the event of an audit.

C. Administrative Requirements

As stated above, the interim regulations require that a disclosed estimation methodology be filed on a one-time basis with the Commission, the natural gas supplier, and the appropriate State or local authority. The monthly affidavits setting forth estimates made in accordance with the methodology must be filed each month only with the supplier. Users may designate as "confidential" the appropriate portions of the calculations set forth therein.

Each month the supplier must be notified by means of the affidavit which must be submitted within five working days after the meter(s) is read by the supplier, in order to give the supplier sufficient time to render a bill based on the affidavit. The methodology to be used for the January 1980 affidavit must be filed with the Commission, the supplier, and the State or local regulatory authority having jurisdiction over the natural gas service provided to the facility before the affidavit is submitted to the supplier.

If an industrial user who claims a partial exemption fails to file a methodology or a monthly affidavit, then the total volume of natural gas supplied to the facility by the supplier shall be incrementally priced.

Further, the owner or operator of an industrial facility who claims a partial exemption under this part must, for a period of at least three years, retain all records, documents and data which formed the basis of the methodology and the monthly affidavits.

Paragraph (g) of § 282.207 requires the natural gas supplier to keep on file and make available to the Commission or Staff, upon request, the monthly affidavits.

The regulations in § 282.207 require that the estimation methodology and the monthly affidavits be signed, under oath, by two people. The methodology must be signed by (1) a responsible company official and (2) a person with some degree of responsibility for formulating the methodology. The monthly affidavit must be signed by (1) a responsible company official and (2) the person performing the calculations.

If the industrial user decides to modify the estimation methodology, the user must file a revised methodology with the Commission, the supplier, and the appropriate State or local agency before using the new procedure in the monthly affidavit.

The joint comments of the Process Gas Consumers Group, the American Iron and Steel Institute, and the Georgia Industrial Gas Group (PGC, *et al.*) proposed that the natural gas supplier serving a facility should have to concur in the estimation methodology. The United Distribution Companies (UDC) and individual natural gas suppliers who submitted comments objected to the necessity of the supplier's approval of the methodology. These commenters argued that this requirement would raise the issue of a supplier's liability in the event the Commission later rejected the disclosed methodology. Furthermore, some suppliers pointed out that they lack the technical depth that would be required to justify the estimation methodologies selected by industrial users.

The Commission believes a heavy burden would be placed on natural gas suppliers if their concurrence in estimating methodologies were required. Therefore, the interim regulations below do not impose such a requirement on natural gas suppliers.

That portion of the regulations in § 282.204 which allowed a supplier-customer agreement to be used for the monthly determination of exempt usage of natural gas is superseded by this interim rule. Section 282.204 is therefore amended below to conform to the disclosed estimation methodology approach set out in § 282.207.

The regulations set forth below reflect certain conforming amendments to the Part 282 regulations required by the disclosed estimation methodology approach.

IV. Submetering Requirement

The technical conference was extremely valuable as a means of gathering technical data on the advantages and disadvantages of submetering. The information which was submitted by those with substantial technical knowledge regarding problems associated with the installation and maintenance of gas meters within an industrial facility has provided the Commission with information which it did not previously have. With this background of knowledge, the Commission will review the submetering requirement which is due to become effective November 1, 1980, as it gains knowledge and experience under the interim rule below.

V. Effective Date

These regulations are being issued effective immediately on an interim basis, because the Commission finds that the need to have the estimating procedures in place before January 1, 1980, constitutes good cause to waive the thirty day publication requirement contained in section 553(d) of the Administrative Procedure Act. The Commission requests data, views or arguments with respect to these regulations. The Commission will consider the comments and the methodologies filed to see whether revisions are warranted. After evaluating the information received, the Commission will revise these regulations as appropriate.

VI. Comment Procedures

A. *Written Comments.* Interested persons are invited to submit written comments, data, views, or arguments with respect to this interim rule. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426 and should reference Docket No. RM80-16. an original and 14 copies should be filed. All comments received prior to 4:30 p.m. EST, February 1, 1980, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street NE., Washington, D.C. 20426, during regular business hours.

B. *Public Hearing.* A public hearing on this interim rule will be held in conjunction with other proposals to be issued with respect to the incremental pricing program. The exact date, location, and procedures for the hearing will be announced at a later date.

(Natural Gas Policy Act of 1978, Pub. L. No. 95-621, 92 Stat. 3350, 15 U.S.C. 3301, *et seq.*)

In consideration of the foregoing, the Commission amends Part 282 of Subchapter I, Chapter 1, Title 18, Code of Federal Regulations, as set forth below, effective immediately.

By direction of the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,114]

45 F. R. 767 (January 3, 1980)

18 CFR Parts 201, 204, and 282

[Docket No. RM79-14; Order No. 49-A]

Regulations Implementing the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978

Issued: December 27, 1979.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Order Granting in Part and Denying in Part Petitions for Rehearing, Amending Regulations, and Denying Motions to Waive Regulations and Accept Late-Filed Petitions.

SUMMARY: The Federal Energy Regulatory Commission hereby issues an order in response to the petitions which are filed requesting rehearing or clarification of Order No. 49, which contained final regulations implementing the incremental pricing program mandated by the Natural Gas Policy Act of 1978. This order on rehearing grants in part and denies in part the petitions for rehearing. The order also states that three notices of proposed rulemaking will be issued in the near future by the Commission in conjunction with the Commission's disposition of the petitions for rehearing. The grant of certain of the petitions necessitates amendments to the incremental pricing regulations. These amendments are set forth at the end of the order.

EFFECTIVE DATE: December 27, 1979

FOR FURTHER INFORMATION CONTACT:
Nancy E. Williams, Deputy Assistant General Counsel for Regulatory Development, 825 North Capitol Street, N.E., Room 8100-I, Washington, D.C. 20426, (202) 357-8033.

In the matter of Order granting in part and denying in part petitions for rehearing, reconsideration, modification, or clarification, amending regulations, and denying motions to waive regulations and accept late-filed petitions.

Issued: December 27, 1979.

I. Filed Petitions

On September 28, 1979 (44 FR 57725, October 5, 1979), the Federal Energy Regulatory Commission (Commission) issued in Order No. 49 final regulations which in part implement Title II of the Natural Gas Policy Act of 1978 (NGPA). Order No. 49, along with companion Orders Nos. 50 and 51, sets forth the regulations necessary for implementation of Phase I of the incremental pricing program required by Title II.

Pursuant to section 506 of the NGPA and § 286.102 of the Commission's regulations, persons may petition the Commission for a rehearing of any rule issued by the Commission under the NGPA.

Timely petitions for rehearing of Order No. 49 were filed by the Atlanta Gas Light Company, the Brooklyn Union Gas Company, Cities Service Gas Company,[1] Consolidated Gas Supply Corporation,[2] the Mississippi River Transmission Corporation, Natural Gas Pipeline Company of America, Southern Natural Gas Company,[3] Tennessee Gas Pipeline Company, a division of Tenneco Inc., Midwestern Gas Transmission Company and East Tennessee Natural Gas Company (a joint application),[4] Tuna Research Foundation, Inc.,[5] United Distribution Companies, United Gas Pipe Line Company, and Associated Gas Distributors.[6]

Late petitions for rehearing were filed by Laclede Gas Company, the National Food Processors Association,[7] the National Forest Products Association (NFPA) and the American Plywood Association (APA) (a joint application),[8] and the American Paper Institute, Inc. (API). The National Food Processors Association and the NFPA and APA filed motions requesting that their petitions be accepted for filing although filed out of time. National Food, NFPA and APA state that their petitions were not filed within the 30-day filing period by a matter of minutes, but were promptly filed on the following, or 31st day. The API requested via a letter that its petition be accepted as timely filed, argued that the 30-day period for filing petitions for rehearing of a rule adopted in an informal rulemaking proceeding should be calculated on the basis of the date that the regulations are published in the Federal Register, not the date that the regulations are issued by the Commission. Laclede Gas Company submitted no explanation for its filing three days after the October 29th deadline.

The Commission believes that delay in the preparation and filing of documents before the Commission does not comprise good cause for the Commission to waive its regulations pertaining to the filing of applications for rehearing. And, although the Commission notes with interest the argument of API, it is not persuaded that sufficient good cause has been shown by API as to why its inquiry into Commission rules of practice and procedure was not commenced prior to a date close to the end of the 30-day period following the issuance date of Order No. 49. For these reasons, the Commission will treat these four late-filed petitions as petitions for reconsideration.[9] As such, the merits of the arguments contained in these petitions have been considered by the Commission and are addressed below.

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[1] The petition of Cities Service includes requests for reconsideration and modification.

[2] The filing of Consolidated Gas Supply Company was styled as a Motion for Clarification or Application for Rehearing.

[3] Southern Natural's petition includes a request for clarification.

[4] This joint application includes requests for reconsideration and modification.

[5] The filing of Tuna Research was not specifically styled as a petition for rehearing, but the Commission has determined to treat it as such for the reasons that it is in substance a petition for rehearing and it was timely filed.

[6] The petition filed by Associated Gas Distributors was a joint application for rehearing of Orders Nos. 49 and 50. The application for rehearing of Order No. 50 has been treated in a separate order.

[7] The petition of National Food Processors includes a request for clarification.

[8] The petition of NFPA and APA includes a request for reconsideration.

[9] The Commission's consideration of these filings and action in response thereto does not serve to waive the Commission's right to assert that the petitioners are not entitled to seek judicial review of the Commission's order herein because they failed to apply timely for rehearing of Order No. 49. See *Boston Gas Company* v. *FERC*, 575 F.2d 975, 977–980 (1st Cir. 1978).

In addition, by letter of October 5, 1979, from the Honorable Pete V. Domenici, United States Senator from New Mexico, a letter dated October 3, 1979, was sent to the Commission discussing certain facts with respect to Gas Company of New Mexico. On October 15, 1979, the Chairman of the Commission responded to Senator Domenici and stated that the October 3, 1979 letter would be treated as an application for rehearing without prejudice to Gas Company of New Mexico filing a further request for rehearing. An additional letter on behalf of Gas Company of New Mexico, dated October 29, 1979, was filed with the Commission on October 29, 1979. This letter stated that Gas Company of New Mexico did not object to the October 3, 1979 letter being treated as a petition for rehearing.

Further, Commissioner George R. Hall referred to the Secretary of the Commission a letter dated November 27, 1979, on behalf of the California Carpet Finishing Company, and requested the Secretary to treat the letter as a petition for rehearing. The Commission has consider this request and determined to treat the letter as a petition for reconsideration, treating it in a manner identical to the late-filed petitions for rehearing described above.[10] A second letter with respect to the situation addressed by the California Carpet Finishing Company on behalf of Customweave Carpets, Inc. was received under date of November 27, 1979. This letter was referred to the Secretary of the Commission by Commissioner Hall for placement in the public file of this docket.

On November 8, 1979, the Brooklyn Union Gas Company filed a "Request for Prompt Clarification" of certain provisions of the regulations set forth in Order No. 49. On November 28, 1979, a joint "response" to Brooklyn Union's request for prompt clarification was filed by the North Carolina Utilities Commission, the public staff of the North Carolina Utilities Commission, the Attorney General of North Carolina, North Carolina Natural Gas Corporation, Pennsylvania & Southern Gas Company, Piedmont Natural Gas Company, Inc., Public Service Company of North Carolina, and United Cities Gas Company. The merits of these filings have been considered by the Commission and are addressed below.

On November 26, 1979, the Commission issued an order granting rehearing of Order No. 49 solely for the purposes of further consideration.

On December 10, 1979, the Brooklyn Union Gas Company filed a "Request for Expedited Disposition of Issue on Rehearing in Light of New Evidence." The argument raised in this petition is addressed below.

Finally, the Commission is in receipt of four letters, dated November 9, 1979, December 5, 1979, December 8, 1979, and December 17, 1979, submitted on behalf of Nitram, Inc. The Commission has determined to treat these four letters, in combination, as a petition for reconsideration.[11] The merits of the arguments raised in these letters are discussed below.

The Commission has considered the numerous arguments raised in all of the filings described above. Based on this analysis, the Commission has determined to grant in part and deny in part rehearing of Order No. 49, amend certain provisions of the regulations contained in Parts 201, 204 and 282, and clarify certain aspects of Order No. 49.

II. Issues Raised in the Petitions.

Several of the petitions for rehearing were addressed to two main issues: (1) the Commission's assertion of jurisdiction in Order No. 49 to require that incremental pricing surcharges be passed through to direct industrial customers of interstate pipelines; and (2) the prorating fraction which was prescribed for the allocation of maximum surcharge absorption capabilities (MSAC) among suppliers.

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[10] *Id.*

[11] *Id.*

Both of these issues received considerable comment and discussion in the course of the rulemaking proceeding which preceded adoption of Order No. 49.

In addition to these issues, however, the petitions raised numerous other points, some of which had not been discussed in comments submitted on the proposals upon which Order No. 49 was based. Each of the issues raised in the petitions is discussed below, and where appropriate, a description is set forth of the amendments hereby adopted to the Part 282 regulations which are adopted in response to the petitions. In three instances, the Commission has determined to issue notices of proposed rulemaking with respect to amendments to its regulations, two of which the petitions for rehearing argue are necessary. Finally, a number of clarifications are set forth below, which serve either to clarify certain provisions of the regulations contained in Order No. 49 or statements made in the preamble to those regulations.

A. Definition of "Agricultural Use".

1. *Amendments Adopted.*—The NFPA and APA and the API request in their petitions that the definition of "agricultural use" be expanded to encompass wood processing. Section 206(b) of Title II of the NGPA exempts natural gas utilized for an "agricultural use" from incremental pricing surcharges. Specifically, NFPA and APA request that the processing of wood in order to obtain plywood and particleboard be deemed an "agricultural use" for purposes of the incremental pricing program, while the API makes a similar request with respect to the processing of wood in order to obtain paper or paperboard.

NFPA/APA's petition argues that "wood is, by any dictionary definition, a 'natural fiber'." Both petitions note that wood processing was not certified as an "essential agricultural use" for purposes of section 401 of the NGPA, but state that such certification was denied on a "storability" criterion, not on the basis that wood is not a "natural fiber."

Both petitions argue that the same logic which led the Commission to include within the definition of "agricultural use" certain textile operations should lead the Commission to treat the processing of wood as an agricultural use.

The Commission agrees with the petitioners that wood is a natural fiber and as such the processing of wood comes within the definition of "agricultural use" set forth in 206(b), in that "agricultural use" is defined to include "natural fiber processing."

For this reason, the Commission hereby amends the definition of "agricultural use" set forth in § 282.202(a) to include Standard Industrial Classification (SIC) Codes 2421, 2435, 2436, and 2492, as requested by NFPA/APA, and SIC Codes 2611, 2621, 2631, and 2661, which have been identified by Commission Staff as those encompassing the processing of wood into paper and paperboard in a usable form, prior to its conversion into end products. This criterion for identification of operations which process wood into paper and paperboard is consistent with API's request.

The exemption affidavit used for the incremental pricing program has also been modified to reflect the above changes.[12] A revised version of that affidavit is set forth below and copies of the revised version are available in the Commission's Office of Public Information.

2. *Natural Gas Used as a Boiler Fuel in the Production of Fertilizer.*

The statutory definition of "agricultural use" provides that natural gas shall be considered to be used for an agricultural use to the extent such use is "as a process fuel or feedstock in the production of fertilizer, agricultural chemicals, animal feed, or food." Letters have been submitted to the Commission on behalf of one company, Nitram, Inc., which uses natural gas as a boiler fuel in the production of ammonium nitrate fertilizer. This company argues that it must use the steam raised in its boilers which consume gas in order to manufacture the fertilizer, and thus its use of gas is as a "process fuel" in the manufacture of the fertilizer. This company requests the Commission to define "process fuel" as it appears in the section 206(b) definition of "agricultural use" to include the use of gas where the boilers form an integral step in the process required to manufacture the final product.

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[12] The version of the exemption affidavit set forth below also reflects changes consistent with the provisions of an interim rule issued today in docket No. RM80-16, *Disclosed Estimation Methodology Approach for Determination of Volumes of Natural Gas Used for Exempt Purposes under the Incremental Pricing Program.*

Commission Staff has discussed with Staff of the Department of Agriculture whether the definition of "agricultural use" in section 401(f)(1) of the NGPA (which is identical to section 206(b)(3) except for the "necessary for full food and fiber production" test in section 401) would include the use of gas as utilized by Nitram, Inc.[13]

These discussions lead the Commission to conclude that this issue, for purposes of the incremental pricing program, would benefit from further public comment. Thus, we have opened a docket for purposes of receiving comment on whether a rulemaking proceeding should be instituted to provide an exemption to natural gas used as a boiler fuel to raise steam, which in turn is utilized in the production of fertilizer. Any such comments should be submitted in Docket No. RM80-18. If the comments received persuade the Commission that a rulemaking proceeding should be instituted, the Commission would propose an exemptive rule under the authority of section 206(d) of the NGPA. By the terms of section 206(d), any exemptive rule adopted by the Commission would have to be submitted to the Congress for its review and possible one-House disapproval prior to the rule becoming effective.

B. *Direct Sales.*

Atlanta Gas Light Company, Associated Gas Distributors (AGD) and Laclede Gas Company allege that the Commission erred in providing that the MSAC's of direct industrial customers of an interstate pipeline could be calculated as the difference between the contract rate (negotiated by the customer with the supplying pipeline) and the applicable alternative fuel price ceiling. Atlanta Gas and AGD both argue that the Commission should require that MSAC's of such customers be determined with reference to the unit cost allocated to such sales in the interstate pipeline's most recent rate case determination. Petitioner AGD states that the regulations as adopted invite abuse, since under them "windfall profits" are "easily available" to an interstate pipeline.

In contrast, several pipelines—Cities Service Gas Company, Southern Natural Gas Company, Tennessee Gas Pipeline Company, United Gas Pipe Line Company, and Mississippi River Transmission Corporation—alleged error in the Commission's assertion of jurisdiction to ensure passthrough of incremental gas costs to direct sale customers. These petitioners request the Commission to retract its assertion of the right to exercise this jurisdiction at some time in the future.

The Commission noted in Order No. 49 that it currently has insufficient data to conclude that the regulations adopted with respect to direct industrial customers would engender a situtation which is "real or merely theoretical". Further, the Commission stated that it would not undertake to adopt a regulatory solution to the problem if proved to be real unless it was established as of a scope which needed to be so addressed.

The Commission believes the issue of its jurisdiction with respect to direct industrial customers of interstate pipelines was sufficiently discussed in

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[13] The Commission has been informed by letter of December 19, 1979, that the Department of Agriculture will issue a proposed interpretation of the list of essential agricultural uses certified pursuant to section 401 of the NGPA (7 CFR 2900.5) to this effect.

Order No. 49 and the public comment proceedings which preceded the issuance of that Order. No arguments have been raised in the petitions for rehearing which had not been raised previously. The Commission has not altered its position with respect to this issue and believes that further discussion is not needed at this time.

AGD in its petition urges the Commission to establish a "rigorous monitoring program" in order to ascertain instances of abuse under the regulations as adopted, if the Commission does not move to amend the regulations to guard against such abuse.

The Commission does not believe at the present time that a special program need be put in place to monitor the activity in the direct sales market. It appears, based on the filings received thus far, that adequate information is being furnished to the Commission in order for it to assess the extent to which the incremental pricing program might be circumvented by contract renegotiations. This information will be periodically reviewed and the Commission will be advised if the "real" problem reference above becomes of a size that would warrant Commission consideration.

Southern Natural, in addtion to opposing the Commission's assertion of jurisdiction, requested clarification that any further action the Commission might take in the exercise of that jurisdiction would be via a generic proceeding as contrasted to proceeding on an adhoc basis with respect to individual situations.

It is the Commission's intent that any further action on its part with respect to the exercise or implementation of the jurisdiction with which it believes it is vested would be through an informal rulemaking proceeding, so that affected parties would have full opportunity to comment on the actions proposed by the Commission to address situations considered to be in need of a regulatory solution.

C. *Prorating Fraction*

1. *Docket to be Held Open*

Natural Gas Pipeline Company of America, Mississippi River Transmission corporation, Southern Natural Gas Company, United Distribution companies (UDC), and AGD requested in their petitions for rehearing that the Commission revised the fraction adopted for the allocation by a supplier of the maximum surcharge absorption capability (MSAC) on its system among its multiple suppliers. The pipeline companies argued that the fraction results in a heavier assignment of surcharges to pipelines further "downstream". Thus, the fraction would result in an allocation of surcharges to "downstream" pipelines which would ultimately have to be cleared into the general purchased gas costs adjustment (PGA) account rather than being absorbed by non-exempt customers. If such costs were placed in the PGA account, they would ultimately be borne to some extent by exempt customers.

AGD argued that the fraction which was adopted discriminates against distributors which are dependent to a significant degree on non-pipeline sources of high cost supplies which carry no incremental costs that are subject to passthrough.

The Commission explicitly recognized that the prorating fraction adopted in the final regulations reflected the needs of administrative practicality and feasibility and that it was not an academic "ideal". The procedure adopted also reflected the Commission's concern that the prorating fraction not create the potential for a significant amount of absorption capability to be "shielded" from allocation of surcharges.

The Commission acknowledges its concern with respect to the issue, however. The Commission further believes that the issue is one which will come into sharper focus as experience is gained under the incremental pricing program. UDC included in its petition for rehearing a number of hypothetical numerical examples on this question, which indicate that the issue, and the considerations which the Commission should look to in balancing competing equities, change form as the relevant variables change.

For this reason, the Commission has determined to grant rehearing on this issue for the purposes of further consideration. The Commission will hold the issue open until the end of 1980 before rendering a decision on the merits. As experience is gained in the implementation of the program, petitioners are encouraged to supplement their petitions for rehearing with data indicating the actual effects of the prorating fraction as adopted. In addition, the Commission has directed the Staff to prepare for the Commission by the end of 1980 a report on the actual results of the prorating procedure currently included in the regulations.

If it appears from the data submitted by impacted parties and from the Staff analysis that amendments to the prorating procedure are necessary, the Commission will take action to issue such amendments.

2. *Canadian Supplies Which Do Not Carry Incremental Costs*

In the course of implementing the current prorating procedure, the Commission has become aware that one aspect of that procedure leaves open the potential for a significant amount of absorption capability to be shielded on certain distribution systems. This could occur where a supplier acquires a large volume of Canadian gas that does not carry incremental costs subject to passthrough from a supplier which is a "natural gas supplier", as defined in § 282.103 of the incremental pricing regulations. In such a situation, the purchasing supplier may include the purchased volumes in the prorating fraction, as currently structured. Since such volumes do not, however, carry incremental costs, their inclusion in the fraction serves to "shield" a portion of the absorption capability located on the supplier's system.

The main objective of the prorating fraction as adopted was to prevent the "shielding" of absorption capability to the greatest extent administratively feasible. The Commission believes that it would be administratively feasible to segregate the Canadian volumes not bearing incremental costs from the rest of the purchased flow. Thus, in a separate docket, the Commission will propose to require that such Canadian supplies be segregated and that they not be included in the prorating faction. The notice of proposed rulemaking in that docket will set forth regulatory language to implement the Commission's proposal.

The Commission has not previously requested comment on this issue and it is for this reason that this proposal of the Commission will be noticed separately as a proposed rule, upon which comment will be received prior to the Commission's making a final decision on the matter.

D. *Small Boiler Facility Exemption*

1. *Statutory Provisions*

Four of the filed documents—the petition for rehearing of Natural Gas Pipeline Company of America, the letter of the California Carpet Finishing Company, the letter of Customweave Carpets, Inc., and the petition for prompt clarification of Order No. 49 filed by the Brooklyn Union Gas Company—request amendments to address the situation which results from the two-pronged test for a "small boiler" which is set forth in section 206(a)(1) of the statute. Under that test, any facility in existence on the date of enactment of the NGPA which used 300 Mcf or less of gas for boiler fuel on an average day in the peak month of use in the base period selected by the Commission, i.e., 1977, is eligible for an exemption from incremental pricing surcharged on the basis that it is a "small" boiler facility.

This test thus grants an exemption to facilities which may have had abnormally low usage in the base period, for reasons such as curtailment. The two-prong test also grants an exemption to facilities which had no usage in the base period because they simply were not in operation in 1977, and to facilities which were not consuming natural gas at that time. All three types of facilities may, however, currently and under normal operations, use much greater quantities of gas than 300 Mcf per day.

The Commission agrees with petitioners that the "loophole" which exists in the statute and gives such facilities an exemption can result in inequitable treatment of these facilities as compared to their competitors. However, the Commission recognizes, as evidenced by the joint response of North Carolina entities to Brooklyn Union's petition, that this issue is of significant interest and the subject of differing views. For these reasons, the Commission will by separate notice propose to amend its regulations so that the three categories of facilities described above would be subject to being incrementally priced as to their non-exempt use of gas. This rulemaking will be conducted on an expedited schedule so that the Commission's position in this matter can be finalized at an early date. Until such time as the Commission reaches a final determination on this issue, however, the current regulations will govern the question of which facilities are or are not eligible for an exemption from being incrementally priced as to their use of natural gas.

2. *"Existing" Facilities and Changes of Circumstances.*—The petition of Natural Gas Pipeline requested clarification of the term "in existence" and the "change of circumstances" rule contained in § 282.205. The Commission agrees that both terms would benefit from clarification and believes it would be useful to formalize the informal interpretations Staff has given of these terms over the past several weeks.

The Commission further believes that public comment on these clarifications would be helpful, and thus will include these two amendments as part of the proposed rulemaking described above which will be issued to address small boiler facilities.

3. *"New" Small Boilers.*—At the time of issuance of Order No. 49, the Commission issued a proposal to extend the small boiler exemption to facilities constructed since the enactment date of the NGPA. That proposal was noticed as Docket No. RM79–48.

A public hearing was held and written comments were received with regard to the proposal on "new" small boilers. However, the record which was developed was not extensive. Further, those comments which were submitted raised certain valid concerns with respect to the proposal.

For these reasons, the Commission has determined to issue a further notice of proposed rulemaking in Docket No. RM79–48. The further notice will specifically request additional data on the number of facilities which would be affected by the rule were it to be adopted, and will also discuss certain of the problems with the proposal which were noted by those commenters who did submit views on the first notice.

Since issuance of Order No. 49, the Commission has also received a number of petitions pursuant to section 502(c) of the NGPA and § 1.41 of the Commission's regulations requesting adjustments to the regulations in Order No. 49 which govern the small boiler facility exemption.[14] Each of these petitions concerns a facility whose usage of natural gas as a boiler fuel has dropped below the 300 Mcf threshold since 1977. The petitioners thus request exemptions on the basis that they are now "small" facilities.

The Commission believes there may be numerous other facilities whose usage has dropped below the 300 Mcf threshold since 1977 for valid business reasons. Thus, the Commission believes a generic rulemaking would be the most appropriate method of dealing with all such facilities. This category of facilities will be dealt with in the further notice to be issued in RM79–48, to consider whether these facilities should be treated as "newly" small facilities.

Until such time as the rule in Docket No. RM79–48 is finalized and becomes effective (any final rule adopted by the Commission will be subject to

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[14] Petitions on this issue have been received from the following parties: The Illinois Brick Company, Rogers Dye-Finishing; Cordova Chemical Company of Michigan; Howell, a division of Burd, Inc.; BASF Wyandotte Corporation; Cerro Copper Products Co.; NCR Corporation; and Valentine Sugars, Inc.

Congressional review), proceedings on the 502(c) applications that the Commission has received will be stayed and the currently effective regulations will govern which facilities are eligible for exemption from incremental pricing surcharges.

4. *Question No. 6 on the Exemption Affidavit.*—A number of questions have been raised since the initial issuance of the exemption affidavit as to the meaning of question No. 6 on the affidavit. If question No. 6 can be answered in the affirmative, a user may certify his facility is "small" and thus eligible for the small boiler exemption. Many commenters asserted that the original form of the question was ambiguous and would permit an applicant to respond in the affirmative who did not in fact meet the "300 Mcf or less on the average day in the peak month of use" test which is set forth in § 282.203 of the regulations.

The Commission does not believe that the original form of question No. 6 was ambiguous, in that the wording of the question tracked the language of section 206(a) of the NGPA and § 282.203 of the regulations. However, the number of queries raised with respect to the question led us to believe a revision of the question would eliminate a significant amount of confusion.

Thus, question No. 6 was revised and was first issued in a revised version of the affidavit dated November 2, 1979. All users who submitted earlier versions of the affidavit are advised to review their filing and compare their answer to question No. 6 with the answer they would give to the revised version of question No. 6. The revised form of the question is included in the most recent version of the affidavit, which is appended hereto. If users find their answers to the two questions are different, they should notify both their natural gas supplier and the Commission as to the change.

E. Inclusion of Local Distribution Companies in Incremental Pricing Program

As noted above, two documents on behalf of Gas Company of New Mexico have been filed with the Commission. The Gas Company has argued for an exemption from the incremental pricing program for those local distribution companies that only rely to a small degree on supplies from the interstate market. As discussed in some detail in Order No. 49, the Commission has taken the position that any local distribution company which is dependent to some extent on interstate supplies becomes, by virtue of that dependence, subject to the incremental pricing program.

One petition has also been filed with the Commission under section 502(c) which requests exemption from the program for the reason that interstate gas represents only a small portion of petitioner's supplies.[15]

Gas Company of New Mexico suggested that the Commission consider a *de minimis* rule, which would provide that a local distribution company would be exempt from the program if it was only dependent on the interstate system for a small percentage of its supplies.

The Commission is not opposed to consideration of such a *de minimis* standard, if it were possible to determine a threshold percentage which was equitable and practicable. From the filings received thus far, the Commission has not been able to identify such a threshold. However, the Commission will continue to consider the question and stands ready to propose adoption of such a standard should it become apparent that it is possible to formulate a viable standard.[16]

F. Reduction of MSAC's by States or Local Distributors

In its petition for rehearing, the Brooklyn Union Gas Company requested the Commission to "adopt a timely and clear policy that rate structure or cost allocation changes made at the local or state level subsequent to enactment of Title II which have the effect of reducing, or eliminating entirely, a distributor's MSAC will be disregarded in calculating such distributor's MSAC." In its filing of December 10, 1979, entitled "Request for Expedited Disposition of Issue on Rehearing", Brooklyn Union requested the Commission to act promptly to resolve the issue addressed in its petition for rehearing.

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[15] Petitioner on this issue is Lone Star Gas Company.

[16] The disposition herein of this issue is without prejudice to Gas Company of New Mexico applying for a 502(c) adjustment under 15 CFR 1.41.

Brooklyn Union had voiced its concern on this issue throughout its comments filed prior to the adoption of Order No. 49. The Commission considered Brooklyn Union's argument along with all other comments filed in the course of the public comment procedure on the incremental pricing regulations. The Commission's position has not altered since issuance of Order No. 49, but the Commission believes it may be of benefit to state here again its rationale for not granting Brooklyn Union's request.

In general, the Commission has recognized throughout development of the incremental pricing regulations that the phenomenon about which Brooklyn Union is concerned could in fact develop. In those situations where State or local commissions take action to raise industrial rates to the level of the alternative fuel price ceilings established by the Energy Information Administration (EIA) of the Department of Energy (DOE) for the Commission, the Commission does not believe such action, by itself, is necessarily undesirable.

The Commission believes that most commissions will require that higher rates collected from industrial users will be reflected in lower rates to high-priority users, although it is evident that the crediting of surcharges against rates to high-priority users could differ from locality to locality from what it would be under the Commission's regulations.

The subject of State-wide exemptions from the incremental pricing program is discussed in detail in the Notice of Proposed Rulemaking issued December 21, 1979 in Docket No. RM79-47. As stated there, the Commission is not currently of the view that it will either encourage or discourage action taken by States to exempt themselves from the Federal incremental pricing program. If, however, a State (or local commission) were to structure its plan so that the net result were an offsetting of industrial rates within the meaning of section 205(b) of the NGPA, the Commission takes the position that such action would be in violation of the statute.

The Commission's intentions with respect to State actions are set forth in the notice issued in Docket No. RM79-47. With respect to contractual relationships between local distribution companies and their direct sale customers, however, the Commission will continue to monitor this situation, as stated in Order No. 49, to determine if contracts are being renegotiated in order to circumvent the intent of the incremental pricing program.

G. Accounting Regulations

As a result of discussions with impacted parties with regard to the implementation of the incremental pricing regulations, Commission Staff has become aware of three aspects of the accounting regulations promulgated in Order No. 49 which are in need of clarification. Thus, the Commisison on its own motion amends certain provisions of Parts 201, 204 and 282, to address the problem areas noted and to clarify the present regulations.

The first area is the ambiguity which lead to a misinterpretation that there could be a double recovery of incremental costs not subject to incremental surcharges. The problem arises from the inclusion of an estimate of such costs in the current PGA clause and the concurrent deferral of such costs in account 192.1, unrecovered incremental gas costs. The accounting required that those costs be transferred to the PGA account, account 191, unrecovered purchased gas costs, but did not specify the accounting required to offset these costs by the amount already recovered through the current PGA.

The amendments set forth below rectify this deficiency. The amount of incremental costs remaining in account 192.1 following the billing of the applicable incremental surcharge will not flow back through the income accounts by reversing the entry which originally deferred those costs. These costs have, at this point, reverted to the status of purchased gas costs, as opposed to incremental costs, following the determination that they are not subject to incremental surcharge. As such, these costs are compared to the amount of such costs already recovered based on estimates, i.e., the PGA clause, and the resulting over or under collection of the costs is deferred in accordance with the PGA mechanism now in place, taking into account the aspects discussed below.

The Commission anticipates that natural gas suppliers not subject to the requirements of the Uniform System of Accounts will adopt accounting practices consistent with those reflected in the Commission's regulations.

The second aspect of the accounting regulations in need of clarification is the possible shift of gas purchase costs between jurisdictional and non-jurisdictional customers. The spillover of the incremental costs not subject to the incremental surcharge requirements is applicable to both jurisdictional and non-jurisdictional sales volumes. As such, the Commission finds that only that portion of the over or under recovery of those costs discussed above, applicable to jurisdictional sales volumes, are to be deferred in account 191 for collection or refunding in the following PGA period. Stated another way, the Commission finds that the portion of a pipeline's purchased gas costs which cannot be passed through as incremental sucharges should be borne by jurisdictional and non-jurisdictional customers of the pipeline in the same manner they would be borne absent incremental pricing.

Consistent with this finding, each pipeline shall defer in acount 191 over or under collections of only those pipeline gas costs related to the pipeline's jurisdictional sales, to be recovered or refunded in the following PGA period.

The third area of change in the accounting regulations is to remove pipeline supplier surcharges from the estimates of purchased gas costs and the estimates of incremental pricing surcharges. In the review of the first tariff clauses and tariff rate revisions filed by interstate pipelines; it became evident that the regulations as written were causing confusion. The changes below serve to simplify and clarify the methodology for calculating the "reduced PGA."

C. The "Reduced PGA" Approach

United Gas Pipe Line Company requested in its petition for rehearing that the Commission clarify whether or not it intended by adoption of the Part 282 regulations to require the use of a "reduced PGA" rate by interstate pipelines in their sales to direct industrial customers and by local distribution companies in sales to their customers.

The Commission agrees with United's argument that it does not have rate jurisdiction over the two categories of sales noted by United. It was not the intent of the Commission to imply by any statements in the preamble in Order No. 49 that the regulations set forth in Part 282 would require interstate pipelines to adopt a reduced PGA rate as the basis for their direct sales contracts. Nor did the Commision intend to indicate that such a requirement would apply henceforth to sales by local distribution companies to their customers. The Commission through adoption of the Part 282 regulations promulgated a requirement that the reduced PGA rate form the basis of sales only with respect to sales by interstate pipelines to their sale-for-resale customers.

This intent is reflected clearly in the provisions of § 282.504(c)(2), which states that the "rate" which is to be used as the basis for the calculation of the MSAC of an individual industrial boiler fuel facility for a particular month is the "rate per million Btu's (excluding any incremental pricing surcharge), plus taxes, at which the non-exempt industrial boiler fuel facility purchased gas from the natural gas supplier during the previous month." This provision makes clear that the rate to be utilized is the current rate being billed by a facility's supplier, *not* a "reduced PGA" rate. The "reduced PGA" rate must be calculated under the regulations only by interstate pipelines and must be used as the basis for billings only in those billings rendered by interstate pipelines to their sale-for-resale customers.

Further indication of the Commission's intent with respect to this question can be found in the provisions of § 282.503(b)(3), clauses (i) and (ii). These provisions deal with the projected MSAC of an individual industrial facility, or in other words, the estimate of the surcharge which the facility will be able to absorb. The first of the two cited provisions states that the rate a local distribution company should use as the basis for the estimate of the surcharge is the "effective rate per million Btu's at the time of projection * * * unless the local distribution company elects to adjust such rate to reflect general rate changes which it is known will occur during the PGA period under authority of a state or local regulatory body." The second provision prescribes that an interstate pipeline should utilize in its calculations (with respect to its direct sale customers) "its effective contract rate per million Btu's at the time of projection * * * unless the pipeline elects to adjust such rate to reflect rate changes which it is known will occur during the PGA period." Contrary to United's request, the Commission believes that the Part 282 regulations are clear as originally promulgated with regard to this issue and they need not be modified.

H. Purchases from Affiliated Producers

Consolidated Gas Supply Corporation requested in its application that the Commission clarify § 282.301(k)(3), which describes that portion of the acquisition cost of natural gas purchased by an interstate pipeline from an affiliated producer which is subject to incremental pricing.

Consolidated states in its application its belief that the Commission intended to treat purchases from affiliated producers in the same way as purchases from unaffiliated producers. Consolidated avers that the present language of § 282.301(k)(3) does not reflect such an intent, however, since the language of the section refers to the cost of gas produced by the affiliate rather than the first sale acquisition cost incurred by the pipeline. Consolidated also notes that no other categories of gas listed in Subpart C—wherein the portion of purchased cost of the various categories which is subject to being passed through as an incremental pricing surcharge is identified—relate to the cost of the producer, in contrast to the first sale acquisition cost incurred by the pipeline.

The Commission agrees with Consolidated's argument and hereby amends § 282.301(k)(3) to make clear that the portion of the cost to an interstate pipeline which is subject to being passed through as a surcharge is to be determined by reference to the first sale acquisition cost incurred by the pipeline with respect to that purchase. The amended regulation incorporates a cross-reference to § 270.203 of the Commission's regulations, which sets forth when sales by affiliates to pipelines will be considered to be first sales.

I. Emergency Transactions Pursuant to § 157.45, et seq., of the Commissions' Regulations

The Cities Service Gas Company and the Tennessee Gas Pipeline Company (in the joint application noted above) requested in their petitions that the Commission clarify Order No. 49 so as to make clear that the incremental pricing regulations do not apply to emergency transactions conducted pursuant to § 157.45, *et seq.*, of the Commission's regulations.

The two petitions argue that if such transactions were included within the program, a portion of the acquisition costs would have to be passed through as incremental pricing surcharges and a supplier would be required to allocate a portion of its maximum surcharge absorption capability to volumes represented by the emergency transaction volumes.

The Commission never intended that the incremental pricing program would apply to the emergency transactions conducted under the provisions of § 157.45, *et seq.* Had this been the Commission's intent, a provision similar to § 282.301(j), which governs purchases made under the authority of section 311(b) of the NGPA, would have been included in § 282.301.

Both petitioners argue that clarifications are needed to § 282.504(c)(3), § 282.504(d)(3), and § 282.504(a)(2), to clearly exclude emergency transaction volumes from the applicability of those sections. Sections 282.504 (c)(3) and (d)(3) deal only with areas where there are incurred incremental gas costs. Our previous statement makes clear that the Commission does not intend to consider any portion of the costs as incremental gas costs in § 157.45, *et seq.*, transactions. Therefore, the provisions of §§ 282.504(c)(3) and (d)(3) never come into operation and need not be clarified.

With respect to petitioner's request for clarification of § 282.504(a)(2), no such section exists. It appears possible that petitioners intended to cite § 282.504(d)(2), which deals with the allocation to multiple suppliers of the aggregate absorption capability of a natural gas supplier. The terms of this section, and its companion section in the "projected MSAC" provisions, § 282.503(c), could be interpreted so as to include volumes purchased in a § 157.45, *et seq.*, transaction. The Commission hereby states that this interpretation should *not* be followed and that the § 157.45, *et seq.*, volumes should simply not be included in the calculations required under the Part 282 regulations.

However, the Commission also wishes to restate its intention, as has been stated previously, to ultimately rescind the Part 157 regulations, because the Commission prefers that emergency transactions be carried out under the Part 284 regulations, promulgated under the authority of section 311 of the NGPA.

J. Refunds

One petitioner, Natural Gas Pipeline Company of America, requested that the Commission delete § 282.506 of the regulations on the grounds that it is both beyond the jurisdiction of the Commission and impracticable for pipelines to administer. The Commission disagrees that the requirements of § 282.506 are beyond its jurisdiction, since the regulation requires only that the refundable amounts be flowed through to "each appropriate natural gas supplier." The Commission agrees with Natural that it does not have the authority to require that those amounts be flowed on through to end-users.

In addition, the Commission is not persuaded by Natural's reasoning that the regulation as written would create an overly burdensome administrative task. Thus, the Commission denies rehearing of this request. However, this denial is without prejudice to the petitioner, or any other party who believes that the requirements of § 282.506 create a special hardship, filing a request for an adjustment to § 282.506 under the provisions of section 502(c) of the NGPA.

K. Optional Billing Procedure for Interstate Pipeline Direct Sales and for Local Distribution Company Sales-for-Resale

United Gas Pipeline requested in its petition for rehearing that the Commission modify the Part 282 regulations to include an optional billing procedure for sales by interstate pipelines to their direct industrial customers and for sales by local distribution companies to their sale-for-resale customers.

The regulations as adopted include optional billing procedures which can be utilized by interstate pipelines for their sales-for-resale and by local distribution companies with respect to their direct customers. The two optional billing procedures were included in the regulations as a result of comments received during the course of the development of the Part 282 regulations. The optional procedures were specifically designed to provide interstate pipelines and local distribution companies with adequate time to gather all information needed to make the actual calculations which must be made to arrive at surcharges under the "reduced PGA" approach. As noted by United, if the optional billing procedures had not been included, the regulations would require that a great volume of communication, computation and billing be computed within a 10-day period. The Commission acknowledges that the 10-day period may be as inadequate in the two situations cited by United as it is in the two situations currently covered by the regulations.

United requests that interstate pipelines be authorized to use either of the two optional procedures already in the regulations when billing their direct customers. The second procedure would only be useful where the incremental costs to be passed through by the pipeline are less than the aggregate absorption capability on the pipeline's system.

The Commission has determined to amend the regulations to include optional billing procedures for interstate pipelines and local distribution companies similar to the procedures already included in the regulations—i.e., to permit interstate pipelines to bill their direct customers at their applicable alternative fuel price ceilings and to permit local distribution companies to bill sale-for-resale customers at the level of the surcharge estimated for each particular customer.

To grant United's request in full might create the potential for an underestimation of the absorption capability of direct customers. The effect of this would be that high priority customers would pay a higher "reduced PGA" rate than they would have if the estimates had been accurate for the duration of the PGA period in question. Thus, the regulations do not permit an interstate pipeline to bill its direct customers at the level of the surcharge estimated for the customer. The Commission is open to further consideration of United's request, however, should it develop that incremental costs incurred by a pipeline are consistently less than the total absorption capability of industrial customers served by the pipeline.

The amendments to §§ 282.504(c)(4), and (d)(4) which reflect that the optionial billing procedures may be utilized by pipelines and distributors are set forth below.

L. November 1 Submetering Requirement

The National Food Processors Association and the Tuna Research Foundation, Inc., both request in their petitions that the submetering requirements which by the regulations will become effective November 1, 1980, be amended so as not to be mandatory in those situations where the output of a boiler is for both agricultural and non-agricultural purposes. The petitions argue that a submeter in such a situation would not be helpful.

The Tuna Research Foundation requests in the alternative that the definition of "agricultural use" be expanded to include the boiler fuel use of natural gas for the production of pet food. The Commission does not view the production of pet food (into which go the trimmings of tuna) as "food production" and thus one of the uses which by the terms of section 206(b)(3)(A) qualifies as an "agricultural use." As the Tuna Foundation acknowledges, the *process* use (not boiler fuel use) of natural gas used in the production of pet food has been certified as an "essential agricultural use" by the Secretary of Agriculture.

The Commission states for purposes of clarification that § 282.204(d)(6)(i)(B)(*1*) provides that as of November 1, 1980, the volumes of natural gas used for an agricultural purpose "shall be determined on the basis of and to the extent there are submeter reading records for each month, as signed under oath by a responsible company official, that show the extent to which gas is consumed for an agricultural use. . . ." The language of the requirement refers to "submeter reading records" but does not require that a submeter be installed so that the reading of that submeter would indicate the volume of gas used for agricultural (or non-agricultural) purposes. The Commission recognizes that a certain amount of extrapolation from submeter readings will be necessary to calculate usage in the agricultural product situation. In addition, the Commission will assess over the next ten months whether the rules it has adopted governing estimates for the first ten months of the program can be retained in some form for the period after November 1. Those rules are set forth and described in a document issued today by the Commission in Docket No. RM80-16.

Natural Gas Pipeline Company of America petitioned the Commission for deletion of the November 1, 1980, submetering requirement. Natural's request is denied for the reason that this issue received adequate and full discussion before the submetering requirement was adopted. The request is also denied as premature since the requirement does not become effective until November 1, 1980, and the requirement will undergo continuing assessment during the first several months of implementation of the Phase I program. The issue will also receive analysis in connection with the Commission's rulemaking proceeding for promulgation of the Phase II program regulations.

M. Amendments to Filing Requirements

The Commission has received a number of petitions for adjustment under section 502(c) of the NGPA requesting relief from compliance with the filing and accounting procedures contained in Part 282. The petitions basically are one of two types.

One type of petitioner is a supplier who currently purchases no volumes of gas which carry incremental gas acquisition costs. Companies in this situation request that they not be required to make the tariff filings nor to file any of the other reports required under §§ 282.601-603 and that they not be required to keep the accounts required by § 282.502.

The Commission agrees that there is no benefit to be gained from this type of company complying with the requirements of Part 282 as indicated, as long as the situation of each company remains as it is at present.

The second type of petitioner is a company which functions merely as a gatherer of gas from producers, or functions only as a conduit pipeline. This type of petitioner requests relief from the MSAC calculations and reporting requirements contained in §§ 282.503 and 282.504, since his MSAC will always be zero. The Commission believes that certain companies in these situations should be relieved of the MSAC requirements. The Commission presently believes that relief should be granted to three types of companies: (1) a company which is small, is located close to the producer-suppliers, performs only a gathering service, and sells the entirety of the gathered gas to one large interstate pipeline; (2) a company which is in a unique situation and all of its current purchased gas costs are allocated to interstate pipeline purchasers; and (3) a company which sells only to other interstate pipelines and sells to each an isolated, identifiable source of supply.

Companies such as those above should only be relieved of MSAC calculations, however. They should still be required to identify and report to purchasing pipelines each month the incremental gas costs portion of the purchase costs.

The Commission will handle the 502(c) petitions it has received in these areas on a case-by-case basis, since the facts of each are very significant and generic rules which will not sweep too broadly are difficult to formulate at this time.

N. Treatment of District Heating Facilities

The General Counsel of the Commission has to date received four formal requests for interpretation[17] to establish that a district heating facility is not an industrial facility within the meaning of section 201 of Title II and § 282.103 of the Commission's regulations. A district heating facility is, in general terms, a facility which generates steam for sale to the public. The steam may flow to users who would be exempt from being incrementally priced if considered on an individual basis under the program, or it may flow to facilities which would be nonexempt industrial facilities, or it may flow to both types of facilities.

The question is whether the centralized facility which is generating steam should pay incremental surcharges on the gas it purchases to generate the steam.

The Commission believes that the question with respect to district heating facilities is of a general nature and should be handled in this order on rehearing.

The Commission is persuaded that the mere act of raising steam is not sufficient to classify a district heating facility as an industrial facility under the definition in § 282.103(d). It is the use to which the steam is put and not the fact that the steam is raised that should determine the status of such a facility. Ideally, only that portion of gas used to generate steam which ultimately flows to what would be exempt facilities if considered on their own should be exempt from incremental surcharges. As a practical matter, however, a determination of whether or not a facility would be exempt if considered on its own is beset with difficulties.

If this approach were adopted, many of the complexities of the incremental pricing program would be transferred to the steam distribution system, although surcharges to the district heating company would likely be rolled into all steam customers. Thus, otherwise exempt customers could end up paying part of the incremental surcharges, and otherwise nonexempt customers could escape some of the surcharges. Since such a program would be administratively burdensome to all parties involved and would not achieve the statutory goal of flowing incremental gas acquisition costs through to nonexempt customers, the Commission believes that district heating systems which primarily serve nonindustrial steam requirements should be exempted from paying incremental surcharges as to their purchases of gas.

We have determined to use 1977 loads to determine the nature of the loads of district heating systems. Those systems with steam loads which were 50% or more nonindustrial or exempt industrial in 1977 need only complete an exemption affidavit as provided by the Commission for the incremental pricing program (a copy of the affidavit is appended hereto). A responsible company official of a district heating facility which sold 50% or more of its steam load to nonindustrial or exempt industrial customers may answer question No. 5 on the affidavit in the negative and submit the affidavit to the facility's supplier (with two copies to the Commission). Upon receipt of the affidavit, the supplier will consider the district heating facility to be exempt from incremental pricing surcharges. The Commission has determined to require district heating facilities which served (in 1977) loads not primarily residential, commercial, or otherwise exempt to file a petition for adjustment with the Commission under the procedures of 502(c) and § 1.41 of the Commission's regulations. In this context, the Commission believes that if more than 50% of annual steam sales were to nonexempt industrial facilities, the aggregate load should be viewed as not primarily residential, commercial, or otherwise exempt. Petitioners with such steam loads should address the question of why exemption from incremental pricing is necessary to prevent special hardship, inequity, or an unfair distribution of burdens.

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[17] Requests for Interpretation have been received from Baltimore Gas and Electric Company; The Detroit Edison Company; Rochester Gas and Electric Corporation; and the International District Heating Association. The disposition of the district heating facility issue in this order renders individual responses to these requests unnecessary, except as to one request included in the filing of the Detroit Edison Company with respect to § 282.502 of the Commission's regulations.

The definition of "industrial facility" in § 282.103(d) of the Commission's regulations has been amended to incorporate the fifty percent (50%) rule described above.

O. Clarifications of a Technical Nature

1. *Definitions.*— Natural Gas Pipeline Company of America requested that the definitions of the terms "boiler fuel use" and "industrial boiler fuel facility" be added to the other definitions set for in § 282.103. Natural notes that the terms are defined in the statute.

It is, however, not necessary to set forth definitions of the two terms in § 282.103, since the statutory definitions of the terms are adopted in § 280.101. The definitions adopted in § 280.101 are applicable to all regulations set forth in Subchapter I of Chapter I of Title 18 of the Code of Federal Regulations, and the regulations in Part 282 are a subset of Subchapter I.

2. *Treatment of Certain Types of Intrastate Gas.*— One statement included in the preamble in Order No. 49 should be clarified so as to eliminate the confusion which the sentence as written has engendered. The statement appears in the discussion entitled "Prorating of MSAC" and would seem to indicate that a local distribution company that makes any purchase of gas, the price of which is governed by Title I of the NGPA, is treated as an interstate pipeline with respect to such purchases. The statement is too broad in scope and should not be so broad as to include purchases of gas such as described in sections 105 and 106 of Title I. Rather, as stated in section 204(c)(4) of the NGPA, only purchases of gas listed in section 203 or certain other costs as listed in 203(a)(8)(B), (9), or (10) render a local distribution company an interstate pipeline vis-a-vis those purchases. As such, of course, the local distribution company must pass through the incremental costs associated with the volumes to nonexempt industrial customers.

3. *Steam Utilized for Space Heating.*— One of the questions which has been frequently posed to Commission Staff merits discussion in this order. This question is whether or not natural gas used by an industrial facility to generate steam which is in turn used by the facility for space heating purposes is subject to being incrementally priced. The current regulations do not specifically address this question, so that some ambiguity could be alleged to exist as to whether the regulations exclude or include the volumes of natural gas so used.

The Commission is of the belief that gas used for space heating purposes should be viewed in relationship to the use or operation which the space heating supports. In other words, if the space heating is a necessary component of a nonexempt industrial facility, then gas used to generate the steam used for the space heating should be considered as subject to being incrementally priced. If the steam is used to space heat a facility which is eligible for a partial exemption, then the Commission believes that the gas used for space heating purposes should be proportionately attributed to the end-uses of which it forms a component. For example, if a facility receives an exemption for half of its non-space heating boiler fuel use because half of the end-product produced by the facility is an agricultural product, half of the gas used to generate steam for space heating in the facility is also eligible for an exemption.

The question of gas used to generate steam for space heating is addressed in the Commission's interim rule issued today in Docket No. RM80-10 governing how estimates should be calculated during the first ten months of the incremental pricing program.

4. Industrial Facilities Which Generate and Sell Electricity to the Public.

Another question which has been raised to Staff several times relates to the treatment of gas sold to an industrial facility which utilizes the gas to generate electricity which is typically used only by the facility itself. However, the facility may at those times when it is generating more electricity than needed to meet its own demands sell the excess power to the regional grid of which it is a member.

The question then is whether such a sale renders the facility an "electric utility" under the NGPA and as such eligible for an exemption under section 206(c)(2) of Title II. The definition of "electric utility" in section 2(28) of the NGPA is:

> "The term 'electric utility' means any person to the extent such person is engaged in the business of the generation of electricity and sale, directly or indirectly, of electricity to the public."

The Commission takes the position that an industrial facility as described above would be an electric utility to the extent of its sales of power to the public. Thus, the facility would be eligible for an exemption from being incrementally priced to the extent of its purchases of natural gas which are used to generate the electricity which is ultimately sold to the public.

The Commission Orders: For the reasons set forth above, the Commission orders:

A. The petitions for rehearing, reconsideration, modification and clarification are granted to the extent indicated in the body of this order. To the extent not so granted, the petitions are denied.

B. The motions and request for acceptance of late-filed petitions for rehearing are denied.

C. The request for prompt clarification, to the extent not addressed above, is dismissed.

D. The request for expedited disposition is dismissed.

E. Title 18 of the Code of Federal Regulations is amended by revisions in Parts 201, 204, and Part 282, to read as set forth below, effective immediately.

The regulations below are made effective immediately for the reason that they in part grant or recognize an exemption, relieve a restriction, or are interpretative in nature, which is consistent with section 553(d) of the Administrative Procedure Act. The remainder of the regulations deal with accounting regulations, which the Commission views as analogous to rules of practice and procedure, and thus not subject to the section 553(d) requirement.

(Natural Gas Act, as amended, 15 U.S.C. 717, *et seq.*; Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, 15 U.S.C. 3301, *et seq.*; Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.*)

By the Commission.

Kenneth F. Plumb,
Secretary.

Federal Energy Regulatory Commission, Washington, D.C. 20426.

Exemptions from incremental pricing for certain categories of industrial boiler fuel use of natural gas.

Docket No. RM79-14.

Participation is Voluntary.

Copies of executed exemption affidavits filed with the Commission shall be available through the Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426.

Please Read Before Completing This Affidavit

Purpose

The Natural Gas Policy Act of 1978 (NGPA) provides that natural gas used as boiler fuel by any industrial boiler fuel facility will be subject to incremental pricing surcharges unless exempted. The statute provides for certain exemptions from these incremental pricing surcharges. To be wholly or partially exempt from incremental pricing surcharges the boiler fuel must be consumed for one of the statutorily exempt uses. This affidavit serves the purpose of identifying those natural gas uses within your facility which are entitled to a full or partial statutory exemption from incremental pricing surcharges but which could not be identified as exempt through review of the records of your natural gas supplier.

Important

If circumstances or ownership change with respect to your facility, you should immediately notify your natural gas supplier(s) of the change so that the correct amount of surcharge may be calculated as to your gas use. Failure to report changes may lead to civil and criminal penalties under Section 504 of the Natural Gas Policy Act of 1978.

General Instructions

If you claim an exemption from incremental pricing surcharges for all, or a portion, of the gas used by your facility which has been identified by your natural gas supplier as a potentially non-exempt industrial boiler fuel facility, this affidavit should be completed and signed, under oath, by a responsible official associated with the facility. A separate affidavit must be filed for each facility for which a total or partial exemption from incremental pricing surcharges is claimed.

The original and two copies of this affidavit should be submitted to: Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

Also, one copy must be submitted to your natural gas supplier. Additionally, each industrial facility must retain such records, documents and data which formed the basis for the exemption claimed on this affidavit. Definitions which may be helpful in completing this affidavit are provided below.

If you have any questions concerning this affidavit contact Ms. Alice Fernandez on (202) 357–8965.

Definitions

(1) "Natural gas supplier" means an interstate pipeline or a local distribution company.

(2) "Local distribution company" means any person other than an interstate pipeline that receives gas directly or indirectly from an interstate pipeline and which is engaged in the sale of natural gas for resale or for ultimate consumption. A person is not considered as having received gas directly or indirectly from an interstate pipeline if the only service performed by an interstate pipeline for the purchaser is a transportation service.

(3) "Boiler fuel use" means the use of any fuel for the generation of steam or electricity.

(4) "Facility" means all buildings and equipment located at the same geographic site which are commonly considered to be part of one plant, mill, refinery, or other industrial complex.

(5) (a) "Industrial facility" means any facility engaged primarily in the extraction or processing of raw materials, or in the processing or changing of raw or unfinished materials into another form or product.

(b) A district heating facility which sold more than 50% of its steam in 1977 for residential, commercial or industrial uses exempt from being incrementally priced shall not be considered to be an "industrial facility." For purposes of this paragraph, a "district heating facility" is a facility which generates steam which is sold to the public.

(6) "Industrial boiler fuel facility" means any industrial facility which uses natural gas as a boiler fuel.

(7) "Non-exempt industrial boiler fuel facility" means any industrial boiler fuel facility other than any such facility which has been exempted from the incremental pricing program in accordance with Part 282 of the Commission's rules and regulations.

(8) "Agricultural use" means any use of natural gas (a) which is certified by the Secretary of Agriculture under 7 CFR 2900.3 as an "essential agricultural use" pursuant to section 401(c) of the NGPA;

or (b) which is used in the following manufacturing operations as set forth in the *Standard Industrial Classification Manual—1972; provided that,* the use of natural gas in the textile operations is limited as set forth below to the production or processing of natural fiber:

Industry SIC No.	*and Industry Description*
221	Broad Woven Fabric Mills, Cotton.
222	Broad Woven Fabric Mills, Man-made Fiber and Silk (natural fiber processing only).
223	Broad Woven Fabric Mills, Wool (Including Dyeing and Finishing).
224	Narrow Fabrics and Other Smallwares Mills: Cotton, Wool, Silk, and Man-made Fiber (natural fiber processing only).
2257	Circular Knit Fabric Mills (natural fiber processing only).
2258	Warp Knit Fabric Mills (natural fiber processing only).
226	Dyeing and Finishing Textiles, Except Wool Fabrics and Knit Goods (natural fiber processing only).
228	Yarn and Thread Mills (natural fiber processing only).
2291	Felt Goods, Except Woven Felts and Hats (natural fiber processing only).
2293	Paddings and Upholstery Filling (natural fiber processing only).
2294	Processed Waste and Recovered Fibers and Flock (natural fiber processing only).
2295	Coated Fabric, Not Rubberized (natural fiber processing only).
2297	Nonwoven Fabrics (natural fiber processing only).
2299	Textile Goods, Not Elsewhere Classified (natural fiber processing only).
2421	Sawmills and Planing Mills, General.
2435	Hardwood Veneer and Plywood.
2436	Software Veener and Plywood.
2492	Particleboard.
2611	Pulp Mills.
2621	Paper Mills, Except Building Paper Mills.
2631	Paperboard Mills.
2661	Building Paper and Building Board Mills.

(9) "School" means a facility the primary function of which is the delivery of instruction to regularly enrolled students in attendance at such facility. Facilities used for both educational and non-educational activities are not included under this definition unless the latter activities are merely incidental to the delivery of instruction.

(10) "Hospital" means a facility the primary function of which is the delivery of medical care to patients who remain at the facility. Outpatient clincs or doctor's offices are not included in this definition. Nursing homes and convalescent homes are included in this definition.

(11) "Similar institution" means a facility the primary function of which is the same as the primary function of the facility to which it is compared.

(12) "Qualifying cogeneration facility" means a cogeneration facility which meets the requirements prescribed by the Commission pursuant to section 201 of the Public Utility Regulatory Policies Act of 1978.

UNITED STATES OF AMERICA FEDERAL ENERGY REGULATORY COMMISSION

Exemptions From Incremental Pricing for Certain Categories of Industrial Boiler Fuel Use of Natural Gas

1. Name of Company or Organization: ______________________________

2. Name of Facility: ______________________________

____

* * * * *

3. Address:
Number ______________________________
Street ______________________________
City/Town ______________________________
County ______________________________
State ______________________________
Zip Code ______________________________

* * * * *

4. Name of Natural Gas Supplier:
____
____
____

* * * * *

5. Is your facility an "industrial boiler fuel facility", as defined in the "Definitions" of this affidavit?

(a) ☐ No —— Sign and return affidavit.
(b) ☐ Yes —— Continue to 6.

* * * * *

6. Was your industrial boiler fuel facility in existence on November 9, 1978; and, on the basis of records, documents, or data in your possession, was your facility's average daily consumption of natural gas for boiler fuel, for the month of peak usage in 1977, 300 Mcf per day or less?

(a) ☐ Yes —— Sign and return affidavit.
(b) ☐ No —— Continue to 7.

* * * * *

7. Is all of the natural gas consumed as boiler fuel at your facility for an agricultural use?

(a) ☐ Yes —— Sign and return affidavit.

(b) ☐ No —— Continue to 8.

* * * * *

8. Is your facility, in its entirety, any of the following:

(a) A school, hospital, or similar facility?

☐ Yes ☐ No

(b) Used for generation of electricity by an electric generation station owned by an electric utility?

☐ Yes ☐ No

(c) A qualifying co-generation facility?

☐ Yes ☐ No

If the answer is "yes" to any of the above, sign and return this affidavit. If the answer is "no", continue to 52.

* * * * *

9. Is a portion, though not all, of the gas consumed at your facility used as boiler fuel for an agricultural use?

(a) ☐ Yes —— Sign and return affidavit, and see item (1) of the "Notice" below.

* * * * *

10. Is your facility, in part, but not in its entirety, any of the following:

(a) A school, hospital, or similar facility?

(b) Used for the generation of electricity by an electric generation station owned by an electric utility?

☐ Yes ☐ No

(c) A qualifying co-generation facility?

☐ Yes ☐ No

If the answer is "yes" to any of the above, sign and return this affidavit and see item (2) of the "Notice" below.

If the answer is "no" to all questions in items 6 through 10, you should not return this affidavit, but see item (3) of the "Notice" below.

Notice

(1) ***Question 9.***

If you have responded affirmatively to question 9, the volume of natural gas used in your facility which shall be exempt from incremental pricing—

(a) for the period January 1, 1980, through October 31, 1980, may be determined on the basis of a disclosed estimation methodology and monthly estimates which are certified by a responsible company official, in accord with § 282.207 of the Commission's regulations; and

(b) for the period beginning November 1, 1980, shall be determined on the basis of submeter reading records for each calendar month, as signed under oath by a responsible company official, which show the extent to which gas is consumed for an agricultural use and which are furnished to the facility's natural gas supplier as required by the supplier.

- **Certified monthly estimates may be utilized for a period following November 1, 1980, if you have obtained a purchase order for all submeters which will be needed in your facility by November 1, 1980, and expect installation within a reasonable time period.**

(2) ***Question 10.***

If you have responded affirmatively to any part of question 10, the volume of natural gas which shall be exempt from incremental pricing—

(a) for the period January 1, 1980, through October 31, 1980, may be determined on the basis of a disclosed estimation methodology and monthly estimates which are certified by a responsible company official in accord with § 282.207 of the Commission's regulations; and

(b) for the period beginning November 1, 1980, shall be determined on the basis of submeters which permit determination of the volume of exempt usage and which are available to be read by the facility's natural gas supplier, or on the basis of submeter reading records for each month, as signed under oath by a responsible company official, which show the extent to which gas is consumed for an exempt use and which are furnished to the facility's natural gas supplier as required by the supplier.

- **Certified monthly estimates may be utilized for a period following November 1, 1980, if you have obtained a purchase order for all submeters which will be needed in your facility by November 1, 1980, and expect installation within a reasonable time period.**

(3) ***Users Who Do Not Return Affidavits.***

If you do not complete and return this affidavit setting forth your claim to a total or partial exemption, *ALL* gas sold to your facility will be subject to incremental pricing surcharges. However, that volume of gas which is used in your facility for a use other than boiler fuel use will not be subject to incremental pricing surcharges provided that the volume is determined in any of the following ways—

(a) for the period January 1, 1980, through October 31, 1980, on the basis of a disclosed estimation methodology and monthly estimates which are certified by a responsible company official, in accord with § 282.207 of the Commission's regulations; and

(b) for the period beginning November 1, 1980, on the basis of submeters which permit

determination of the volume of non-boiler fuel usage and which are available to be read by the facility's natural gas supplier, or on the basis of submeter reading records for each calendar month, as signed under oath by a responsible company official, which show the extent to which gas is consumed for a non-boiler fuel use and which are furnished to the facility's natural gas supplier as required by the supplier.

- Certified monthly estimates may be utilized for a period following November 1, 1980, if you have obtained a purchase order for all submeters which will be needed in your facility by November 1, 1980, and expect installation within a reasonable time period.

Dated:——————
Signature:——————
Person completing this affidavit:
Name:——————
Title:——————
Phone number:——————

Subscribed and sworn to before me this —— day of ——,
Notary Public:——————

[¶ 30,115]

45 F. R. 1861 (January 9, 1980)

18 CFR Part 157

[Docket Nos. RM79-37 and RM79-43; Order No. 56-A]

Applications for Certificates of Public Convenience and Necessity and for Orders Permitting and Approving Abandonment Under Section 7 of the Natural Gas Act; Amendment Implementing the Natural Gas Act

Issued: January 2, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Order Denying Application for Rehearing of, and Clarifying, Order No. 56 (Budget-Type Certificates—Gas Supply Facilities).

SUMMARY: This order denies rehearing of Order No. 56 because the application therefor presents no new issues which would require reconsideration of that order. In addition, this order clarifies the definition of "gas supply facilities." The technical, clarifying amendment makes more clear the Commission's intent that budget-type certificate coverage be available in situations involving transportation or exchange between two interstate pipelines of natural gas intended for the system supply of a third interstate pipeline.

EFFECTIVE DATE: January 2, 1980.

FOR FURTHER INFORMATION CONTACT:

Frank Markulin, Office of Pipeline and Producer Regulation, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8859.

Bob Nichols, Office of the General Counsel, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8141.

[Order No. 56-A]

Order Denying Rehearing of, and Clarifying, Order No. 56

Before Commissioners: Charles B. Curtis, Chairman; Georgiana Sheldon, Matthew Holden, Jr., and George R. Hall.

In the matter of budget-type applications; gas supply facilities—amendments to scope of existing regulations (Docket No. RM 79-37) and; amendments to Subpart A, Part 157 of the regulations implementing the Natural Gas Act (Docket No. RM79-43).

Background

On November 1, 1979, the Commission issued Order No. 56, a final rule amending Part 157 of its Regulations Implementing the Natural Gas Act, 44 FR 65055 (November 13, 1979). That order expands the definition of, and raises the limits pertaining to, gas supply facilities. It further provides for the issuance of certificates of indefinite duration, which may be revoked at any time.

One application for rehearing and clarification has been received.[1] It requests that the Commission either tie the total yearly and single project limits to the *Handy-Whitman Index of Public Utility Construction Costs* or revise the regulations annually. It also requests that the Commission make clear that any revocation of a pipeline's budget-type certificate would be for good cause only. It further requests that such revocations be prospective only, from and after the next anniversary date, so that a company would not be adversely affected as to projects planned, commenced or completed prior to any revocation of its budget-type certificate.

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[1] Application of Transcontinental Gas Pipe Line Corporation for Rehearing and Clarification, filed December 3, 1979.

The Commission decided not to utilize the *Handy-Whitman Index* in Order No. 56. As discussed there, increased costs are not the sole concern. Operational, environmental and consumer rate impacts are also concerns that require periodic review of the limits. However, the Commission does recognize the need for an annual review of the dollar limits for budget-type gas supply facilities. Staff has been directed to review the limits annually and report to the Commission on the advisability of adjusting the cost limits.

The Commission will not amend its regulations to provide that budget-type certificates may be revoked only for "good cause" or that a revocation would be effective only on a certificate's next anniversy date. Budget-type certificates are intended as a more efficient manner of complying with the requirements of section 7(c) of the Natural Gas Act with respect to minor, routine facilities. The Commission's discretion to allow or disallow the use of such certificates should not be limited. Revocations, if and when they become necessary, will be effected in a legally permitted and required manner, both as to the method of revocation and its effect on previously planned or commenced projects.

However, the Commission, on its own motion, recognizes the need to clarify § 157.7(b)(4). As pointed out in Order No. 56, budget-type certificates authorize the construction of facilities necessary to effectuate transportation by one interstate pipeline for another or exchanges between interstate pipelines. The use of the word "that" to qualify the words "interstate pipeline company" in the definition of "gas supply facilities" could be read as more restrictive than is intended by the Commission. Specifically, the definition could be read as excluding from its purview those facilities necessary to effectuate the transportation or exchange between two interstate pipelines of natural gas intended for the system supply of a third interstate pipeline. Facilities to effectuate such transportation or exchange transactions are intended to be covered by budget-type certificates. In order to make the regulations more clearly reflect the Commission's intent, the word "that", as it appears in § 157.7(b)(4) is being replaced with the word "an".

(Natural Gas Act, as amended, 15 U.S.C. 717, *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. 3301, *et seq.*; Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.*; E.O. 12009, 42 FR 46267.)

The Commision Finds: (1) Transcontinental's application for rehearing presents no new facts or principles of law which the Commission failed to consider in its November 1, 1979, order, or which having been considered now, warrant reconsideration of that order. Therefore the application is denied.

(2) Since the amendment promulgated herein is a technical, clarifying amendment and does not change the substance of the rule promulgated in Order No. 56, compliance with the public notice and comment requirements of 5 U.S.C. § 553 is unnecessary.

The Commission Orders: (A) The application for rehearing and clarification is denied.

(B) Part 157 of Subchapter E, Chapter I, Title 18, Code of Federal Regulations is amended as set forth below.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,116]

45 F. R. 1862 (January 9, 1980)

18 CFR Part 271

[Docket No. RM80-19; Order No. 64]

Provisions for First Sales of Natural Gas Committed or Dedicated to Interstate Commerce as of November 8, 1978; Order Reissuing Regulations As Final

AGENCY: Federal Energy Regulatory Commission.

ACTION: Order Reissuing Interim Regulations as Final Regulations.

SUMMARY: On December 1, 1978, the Commission issued interim regulations implementing the pricing provisions of the Natural Gas Policy Act of 1978, 43 FR 56448 *et seq.* Among these regulations was Subpart D of Part 271 which provides for first sales of natural gas which was committed or dedicated to interstate commerce as of November 8, 1978. Since that issuance, the regulations of Subpart D have been amended. On consideration of comments received since the issuance of December 1, 1978, and in light of subsequent amendments to Subpart D, the Commission is now reissuing Subpart D as a final regulation. This reissuance is being made without any further amendment.

EFFECTIVE DATE: January 3, 1980.

FOR FURTHER INFORMATION CONTACT: John Conway, Federal Energy Regulatory Commission, Office of the General Counsel, Room 8100–K, 825 North Capitol Street, NE. Washington, D.C. 20426 (202) 357–8150.

Issued January 3, 1980.

A. Background

On November 9, 1978 the Natural Gas Policy Act of 1978 (NGPA), 15 U.S.C. 3301 to 3432, was signed into law. Sections 104 and 106(a) of that Act prescribe prices for sales of natural gas committed or dedicated to interstate commerce [1] on November 8, 1978 (the day before the date of enactment of the NGPA) for which a just and reasonable rate under the Natural Gas Act (NGA), 15 U.S.C. 717 *et seq.*, was in effect on that date.

Section 104(b)(1) of the NGPA stipulates that the maximum lawful price for the first sale of committed or dedicated natural gas may be the higher of either the just and reasonable rate, per million Btu's (MMBtu), established by the Commission which was, or would have been, applicable to the first sale of that gas on April 20, 1977 as adjusted from April 1977 by the monthly equivalent of the annual inflation adjustment factor; or any just and reasonable rate established for that gas by the Commission after April 20, 1977 and before November 9, 1978. Alternatively, section 104(b)(2) permits the setting of an applicable ceiling price for such gas by rule or order of the Commission if the price so set is higher than the maximum lawful price which would otherwise be applicable under the general rule of section 104(b)(1) and if the higher price is just and reasonable within the meaning of the NGA.

Section 106(a) of the NGPA prescribes ceiling prices for committed or dedicated natural gas sold under rollover contracts.[2] Under section 106(a) the general rule is that the applicable maximum lawful price for such gas is the higher of the just and reasonable

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[1] With certain exceptions, section 2(18)(A) of the NGPA defines gas "committed or dedicated to interstate commerce" as "natural gas which is from the Outer Continental Shelf; and natural gas which, if sold, would be required to be sold in interstate commerce (within the meaning of the Natural Gas Act) under the terms of any contract, any certificate under the Natural Gas Act, or any provisions of such Act."

[2] Section 2(12) of the NGPA defines "rollover contract" as "any contract, entered into on or after the date of the enactment of this Act [November 9, 1978], for the first sale of natural gas that was previously subject to an existing contract which expired at the end of a fixed term (not including any extension thereof taking effect on or after such date of enactment) specified by the provisions of such existing contract as such contract was in effect on the date of the enactment of this Act, whether or not there is any identity of parties or terms with those of such existing contract."

Footnotes continued on next page

rate, if any, per MMBtu established by the Commission and applicable on the date the rollover occurred (adjusted by the monthly equivalent of the annual inflation adjustment factor for months following the rollover), or 54 cents per MMBtu as of April 1977 adjusted monthly thereafter by the applicable inflation factor. Section 106(c) provides that an alternative ceiling price may be set by rule or order of the Commission if such ceiling price is higher than the maximum lawful price which would otherwise be applicable under section 106(a), and if it is a just and reasonable price within the meaning of the NGA.

On December 1, 1978 the Commission issued interim regulations implementing the pricing provisions of the NGPA.[3] Subpart D, Part 271 of those regulations implemented the provisions of sections 104 and 106(a) of the NGPA.

Section 271.401 provides that Subpart D applies "to the first sale of natural gas committed or dedicated to interstate commerce on November 8, 1978; and for which a just and reasonable rate under the Natural Gas Act was in effect on November 8, 1978 for the sale of such gas." Section 271.402(a) sets forth the applicable ceiling prices established by vintage and type of producer sale. Section 271.402(b) sets out definitions applicable to Subpart D. Section 271.402(c)(1) sets out rules for certain higher rates for natural gas priced under special relief regulations. Provisions for first sale prices of natural gas for which a just and reasonable rate was established after April 20, 1977 and before November 9, 1978 are set out in § 271.402(c)(2); provisions to require certain filings and Commission approval before higher rates can be charged are set out under § 271.402(c)(3). Finally, a special rule requiring an 83-cent-per-MMBtu deduction as a "carrying charge adjustment" for advance payments for certain post-1974 gas is provided under § 271.403

Since December 1, 1978 Subpart D has been modified in several respects. The provisions respecting the pricing and collection of "minimum rate gas" were amended.[4] The pricing of minimum rate gas, originally in terms of a price-per-MMBtu, was amended to a price on a Mcf basis. This was done because the minimum rate, set forth under § 2.56(b) of the Commission's regulations, is not subject to a Btu adjustment. To have required pricing of minimum rate gas in terms of MMBtu's would, as comments pointed out, have resulted in undue hardship for those selling gas with a low Btu content. In such cases a price less than the 18 cents per Mcf stipulated by § 2.56b(b) would become the applicable minimum rate. In addition, the modifying order added a subparagraph to § 271.402(c) of the interim regulations to exempt the collection of minimum rates from the provisions of § 270.101(b)[5] so that the minimum rate, as adjusted for inflation, could be collected irrespective of contract provision.[6] Finally, the prices originally set forth under §§ 271.402(a) and 271.402(c)(4) were updated[7] and the tables prescribing these prices were moved,

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This definition is supplemented by section 106(a)(2)(B) of the NGPA which provides that, "[f]or purposes of this subsection, the term 'rollover contract' includes any contract which would have been a rollover contract but for the fact that the expiration of the previous contract occurred prior to the day before the date of the enactment of this Act."

[3] Natural Gas Policy Act of 1978: Interim Regulations, Docket No. RM79-3 (issued Dec. 1, 1978), 43 FR 56448 *et seq.* (Dec. 1, 1978).

[4] "Publication of Prescribed Maximum Lawful Prices Under the Natural Gas Policy Act of 1978 and Amendments to Regulations Relating to Minimum Rate Gas," Docket Nos. RM79-3, RM79-4 (issued Jan. 25, 1979), 44 FR 5874 (Jan. 30, 1979).

[5] Section 270.101(b) provides that: [i]f the price established under the contract for the sale of natural gas does not exceed the applicable maximum lawful price, then such maximum lawful price does not supersede or nullify the effectiveness of the price established under such contract. This section implements the provisions of section 101(b)(9) of the NGPA.

[6] In addition to these changes, the order of January 25, 1979 made several technical corrections to cross references of citations within Subpart D, and amended § 154.94 to permit blanket filing for, and collection of, the minimum rate irrespective of an application sales contract.

[7] "Publication of Prescribed Maximum Lawful Prices Under the Natural Gas Policy Act of 1978 and

with necessary amending references, to § 271.101.[8]

B. Summary of Comments

The regulations issued December 1, 1978 reflect consideration of comments submitted to the Commission during November 1978 on preliminary drafts of the regulations. These early comments focused on (1) the provisions for small producer pricing and the attendant definition of small producer; (2) provisions for pricing "minimum rate" gas as adjusted for inflation; and (3) the definition of "replacement contract" as it relates to "successor" contracts. Subsequent comments, made to the interim regulations, expanded on these issues and raised others as well.[9] The comments fall into the following categories: (a) scope of Subpart D; (b) pricing provisions of Subpart D; (c) definitional questions; and (d) procedural questions.

1. Scope of Subpart D

Section § 271.401 states that Subpart D implements sections 104 and 106(a) of the NGPA and applies only to the first sale of natural gas which was committed or dedicated to interstate commerce on November 8, 1978 and for which a just and reasonable rate under the NGA was in effect on that date. One comment observed that this section is silent as to the status of natural gas committed or dedicated before November 8, 1978, for which a certificate of abandonment of service was granted before that date. Advancing the view that such gas should be priced under section 109 of the NGPA, the comment recommended that explicit reference be made in the regulations of Subpart D to the statutory exclusion of such gas from the definition of "committed or dedicated to interstate commerce" (section 2(18)(B)(ii) of the NGPA). This reference, according to the comment, would make it clear that the "catch all" provisions of § 271.904 (which implement section 109 of the NGPA) would apply for gas produced from a well abandoned before November 8, 1978 and not rededicated before that date.

With respect to the main contention of the comment, that Subpart D should reference natural gas which is not "committed or dedicated to interstate commerce", it is our opinion that such a modification is unwarranted and unnecessary. The definitional section of the regulations (§ 270.102(a)) incorporates all NGPA definitions including that of "committed or dedicated to interstate commerce" found under section 2(18) of the NGPA. This is sufficient to indicate the scope of the pricing regulations including those of Subpart D. A specific reference to section 2(18) within Subpart D would therefore be superfluous and would unnecessarily complicate the regulations.

Furthermore, the view that natural gas committed or dedicated to interstate commerce before November 8, 1978 and granted an abandonment of service before that date, and not rededicated, should be priced only under section 109 of the NGPA is incorrect. While such gas might be priced under section 109; it might also be priced under section 105, or section 102 or any other pricing provision (except sections 104 or 106(a)) under which its production and sales characteristics qualify.

2. Pricing provisions

The pricing provisions of §§ 271.402(a) (ceiling prices) and 271.402(c) (applicable higher rates) are the most

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Amendments to Regulations Relating to Minimum Rate Gas," Docket Nos. RM79-3, RM79-4 (issued Jan. 25, 1979), 44 FR 5874 (Jan. 30, 1979); "Amendments to Regulations Relating to Publications of Prescribed Maximum Lawful Prices Under the Natural Gas Policy Act of 1978," Docket No. RM79-39 (issued Apr. 27, 1979), 44 FR 26068 (May 4, 1979); "Publication of Prescribed Maximum Lawful Prices Under the Natural Gas Policy Act of 1978," Docket No. RM79-60 (issued July 25, 1979) FR 48660 (Aug. 20, 1979).

[8] "Publication of Prescribed Maximum Lawful Prices under the Natural Gas Policy Act of 1978," Docket No. RM79-60 (issued July 25, 1979), 44 FR 48660 (Aug. 20, 1979).

[9] In all, some 36 separate comments were received on Subpart D, either in writing or by oral presentation.

complex facets of Subpart D and the ones which engendered the most comment. The comments to these sections addressed four basic issues: the pricing and collection of minimum rate gas; the treatment of natural gas priced under the optional procedure of § 2.75 of the Commission's regulations; "small producer rates"; and the distinction between rollover and replacement contract gas. In addition, some comments were received which sought special interpretations of the pricing provisions.

a. Pricing of minimum rate gas and its collections.—Section 271.402(a) of the interim regulations provides that the minimum rate will be adjusted for inflation by the NGPA inflation adjustment factor. The minimum rate is the 18-cent-per-Mcf rate of § 2.56(b) adjusted for inflation from April of 1977. Section 271.402(b), tracking the provisions of § 2.56b(b), defines the minimum rate and limits the application of that rate to natural gas produced from a well the surface drilling of which commenced prior to January 1, 1973.

On January 25, 1979 the interim regulation was amended to permit the collection of an adjusted minimum rate irrespective of contract authorization. This was done in response to comments which argued that § 270.101(b), in requiring contract authorization to collect a maximum lawful price, conflicted with the concept that a minimum rate could be collected in spite of contract stipulations.

While several comments were received which either explicitly or implicitly endorsed the escalation of the minimum rate by the NGPA inflation adjustment, two comments argued that the escalation was improper. The main point of their argument was that, since the NGPA speaks only in terms of "maximum" lawful prices and does not address a minimum rate, the use of the NGPA inflation adjustment was improper. They recommended that instead of such an approach the Commission undertake a formal ratemaking proceeding to determine new minimum rates.

The minimum rate was last considered in 1975 in Opinion No. 749.[10] At the time, the Commission recognized that the minimum rate should be increased to 18 cents. The increase was intended to promote the expenditure of additional funds to maximize production from older leases in light of inflation and changes in tax liability since *Permian II.*[11] This was consistent with the concept of a minimum rate as ". . . an integral part of the area rate approach. The rate received by a producer must not be so low as to prevent or retard further exploration and thereby decrease possible discovery of gas reserves which will be needed by consumers."[12]

The minimum rate is a just and reasonable rate.[13] The NGPA recognizes the toll taken by inflation and it provides a reasonable mechanism to account for inflation in setting just and reasonable rates. Therefore, the Commission recognizes that the minimum rate set in § 2.56b(b) should be adjusted for inflation in accordance with the provisions of section 104 of the NGPA, and that, as so adjusted, it is in the public interest. We also find that, given the inflation adjustment, a separate proceeding under the NGA to set a new minimum rate for wells commenced prior to January 1, 1973, is unnecessary.

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[10] Opinion 749, "Just and Reasonable National Rates for Sales of Natural Gas From Wells Commenced Prior to January 1, 1973" at 33–35, Docket No. R–478 (issued Dec. 31, 1975), 54 FPC 3090 (1975). The provisions of Opinion 749, as amended, relating to minimum rates are set forth in 18 CFR § 2.56b(b) (1979).

[11] Opinion 749 at 34.

[12] Opinion No. 468, "Area Rate Proceedings" (Permian I), Docket Nos. AR61–1, *et al.*, 34 F.P.C. 159, 231–232 (1965). *See also* Opinion No. 546, "Area Rate Proceeding (Southern Louisiana Area)." Docket No. AR61–2, *et al.*, 40 F.P.C. 530, 623–625 (1968); Order No. 411, "Area Rate for the Appalachian and Illinois Basin Areas," Docket Nos. R371, *et al.*, 44 F.P.C. 1112, 1126–1128 (1970); Opinion No. 658, "Area Rates for the Rocky Mountain Area," Docket No. R–425, 49 F.P.C. 924, 944–947 (1973); Opinion No. 662, Area Rate Proceeding (Permian Basin Area II)," Docket No. AR70–1, 50 F.P.C. 390, 396–397 (1973); Opinion No. 749, "Just and Reasonable National Rates for Sales of Natural Gas from Wells Commenced Prior to January 1, 1973," Docket No. R–478 at 33 (issued Dec. 31, 1975), 54 F.P.C. 3090 (1975).

[13] *See, e.g.*, Opinion No. 662, Area Rate Proceeding (Permian Basin II), Docket No. AR70–1 (Phase I) (issued Aug. 7, 1973) 50 F.P.C. 390, 396–397 (1973); *see also Permian Basin Area Rate Cases*, 390 U.S. 747, 821 n. 113 (1968) (". . . the Commission reasonably concluded that a minimum rate was imperative, and there is no evidence before us that permits the conclusion that its selection was unjust or unreasonable"); *Tenneco Oil Co.* v. *FERC* 571 F.2d 834, 845–46 (5th Cir. 1978).

A second point raised by comments opposed to the inflation adjustment of the minimum rate rests upon a reading of section 101(b)(9) of the NGPA. That section provides that for any price established under a contract for the first sale of natural gas which does not exceed the applicable maximum lawful price, such maximum lawful price shall not supersede or nullify the effectiveness of the price established under such contract. In that the collection of a minimum rate may be made without regard to pricing provisions of a contract, these comments argued that adjusting the minimum rate upward for inflation would violate section 101(b)(9) of the NGPA to the extent that contracts stipulate the payment of a price less than an inflation-adjusted minimum rate.

For the Commission to adopt this logic it must find that section 101(b)(9) of the NGPA worked a change to the doctrine of the *Mobile* and *Sierra* cases.[14] Nowhere in the Act is there any evidence that the Congress intended such a result. Instead, it is quite clear that the provisions of section 101(b)(9) of the NGPA apply only to ceiling prices. While the Conference Report which accompanied the NGPA stipulated that "in no case may a seller receive a higher price than his contract permits;" that admonition must be read in context, a context which speaks to maximum or ceiling prices under the NGPA.[15] A construction of the statute which would overrule a long established precept of law by implication is decidedly disfavored.[16]

More importantly however, section 101(b)(9) applies to ceiling rates circumscribed by contracts. The minimum rate is not such a rate; because of the *Sierra-Mobile* Doctrine, it may be collected irrespective of contract authorization. Moreover, the authority to collect a minimum rate without contract authorization is, in our view, unaffected by the passage of the NGPA (except to the extent the NGA is made inapplicable to particular first sales).[17] We therefore find that the minimum rate, as escalated for inflation in accordance with the provisions of section 104 of the NGPA, is a just and reasonable rate, and it should be collected irrespective of contractual provisions.

One comment, taking the view that the inflation adjustment of the minimum rate sets a new just and reasonable rate for gas delivered from wells spudded prior to January 1, 1973, advocated that a proceeding should be undertaken to establish a minimum rate for natural gas delivered from wells drilled after January 1, 1973. We find that such a proceeding is unwarranted.

The minimum rate was set in the context of very particular circumstances. It was established to prevent producer sales prices which were so low as to be contrary to the public interest. Contracts entered into for post-1973 vintage gas, however, are specifically addressed in national rate opinions,[19] which did not consider minimum rates to be necessary for such gas. Given this fact, we find that the consideration for a minimum rate for post-1973 gas is unnecessary.

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[14] *United Gas Pipe Line Co. v. Mobile Gas Service Corp.* 350 U.S. 332, 345 (1956); *FPC v. Sierra Pacific Power Co.*, 350 U.S. 348, 355 (1956).

[15] "The rule for applications of ceiling prices pertains to maximum lawful prices. All maximum lawful prices are ceiling prices only. In no case may a seller receive a higher price than his contract permits." Joint Explanatory Statement of the Committee on Conference, Sen. Rep. No. 95–1126, 95th Cong., 2d Sess. at 74.

[16] *See, e.g. Isbrandtsen Co., Inc. v. Johnson*, 343 U.S. 779 (1952); *State ex rel. Housing Authority of Plant City v. Kirk*, 231 So. 2d 552 (Fla. 1970); *See generally* Sutherland: Statutory Construction §§ 61.02, 61.03 (Sands ed. 1974).

[17] This is by virtue of section 601 of the NGPA; *see* text accompanying note 27 *supra*.

b. Treatment of natural gas priced under optional certificates.—Section 271.402(c)(1) provides that prices established under § 2.56a(g) (adjusted national rate); § 2.56b(h) (special relief); § 2.76 (special relief in lieu of abandonment), and § 2.77 (special relief in lieu of flared or vented gas), as adjusted for inflation, may be collected instead of the prices set out under § 271.402(a) if they were established before April 20, 1977. Several comments focused on the omission from § 271.402(c)(1) of rates set under § 2.75 (optional procedure). Viewing the optional procedure as a form of "special relief", these comments argued that to omit § 2.75 from the scope of § 271.402(c) was contrary to the specific provisions of both sections 104 and 106(a) of the NGPA. Moreover, they argued that, given the inflation adjustment accorded special relief pricing and minimum rate gas, the selective omission of optional rates worked an unfair discrimination against those whose gas sales were governed by certificates issued under the optional procedure. They advocated either including § 2.75 in the provisions of § 271.402(c)(1) or permitting contract adjustments for prices arrived at through the optional procedure.

The Commission offered the following rationale for omitting § 2.75 from the provisions of § 271.402(c)(1):

> As to producer applications under the optional procedure regulation set forth in § 2.75 of this chapter, a "just and reasonable" rate is that rate established by the Commission in its final order on such applications. However, [because] [sic] the holder of a certificate issued by the Commission under the optional procedure was required to waive the right to receive the applicable national and area rates and other rights under section 4 of the Natural Gas Act and regulations thereunder, we do not believe that the inflation adjustment should apply to rates established under the optional procedure.[20]

Comments, responding to this rationale, argued that pricing provisions waived under the NGA should not pertain to prices set under the totally different regulatory scheme of the NGPA. In support of this argument, they pointed out that sections 104 and 106(a) of the NGPA set up pricing mechanisms which are to apply to *all* just and reasonable rates collected prior to November 9, 1978 and that both of these sections provide that rates should be adjusted for inflation without exception. They argued that those who receive rates set under the procedures of § 2.75 waived no rights under the NGPA and that no such waiver should be implied.

The optional procedure was introduced in mid-1972 as an alternative method for certificating new producer sales of natural gas.[21] The optional procedure permits a producer to request approval of contracts at rates that may exceed the maximum authorized by the applicable nationwide or areawide rate order; allows the Commission to determine in a single proceeding whether "the public convenience and necessity" warrants the issuance of a certificate and whether the rates requested are "just and reasonable"; allows the Commission to issue a permanent certificate which, upon acceptance by the producer, is not subject to change under section 4 of the NGA except to the extent permitted to give effect to certificated escalation clauses; allows the producer to collect rates without risk of refund obligations; and provides an abandonment assurance, if authorized, at the end of a contract term. This procedure has been sustained by the courts.[22]

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[19] *See, e.g.*, Opinion 770–A, "National Rates for Jurisdictional Sales of Natural Gas Dedicated to Interstate Commerce on or after January 1, 1975, to December 31, 1976", Docket No. RM75–14 (issued Nov. 5, 1973); Opinion 699–H, "Just and Reasonable Rates for Sales of Natural Gas from Wells Commenced on or after January 1, 1973 and New Dedications of Natural Gas to Interstate Commerce on or after January 1, 1973", Docket No. R–389–B (issued Dec. 4, 1974), 52 F.P.C. 1604 (1974).

[20] Natural Gas Policy Act of 1978: Interim Regulations at 42 (Docket No. RM 79–5) (issued Dec. 1, 1978), 43 FR 56448, 56471 (Dec. 1, 1978).

[21] Order No. 455, "Optional Procedure for Certificating New Producer Sales of Natural Gas," Docket No. R–441 (issued Aug. 3, 1972), 48 F.P.C. 218 (1972), *as amended*, Order No. 455–A, "Order Clarifying Order and Denying Applications for Rehearing and Stay," Docket No. R–441 (issued Sept. 8, 1972 and corrected Sept. 15, 1972) 48 F.P.C. 477 (1972); Order 455–B, "Amendment of Statement of Policy Relating to Optional Procedure for Certificating New Producer Sales of Natural Gas", Docket No. R–441 (issued Nov. 25, 1974) 52 F.P.C. 1416 (1974); Order No. 455–C "Further Amendment of Statement of Policy Relating to Optional Procedure for Certificating New Producer Sales of Natural Gas", Docket No. R–441 (issued May 19, 1978 and modified on Oct. 11, 1978). The optional procedure is codified in 18 CFR § 2.75 (1979).

Generally, the certificates granted the producer under the optional pricing procedure provided for the requested contract price and definite escalation provisions, deemed satisfactory at the time the certificate was issued. The certificates, as granted, constituted "a final determination that the rates, charges, and services therein specified are just, reasonable and required by the present and *future* public convenience and necessity." [23]

In accepting a certificate under the optional procedure, and the higher rates accompanying a certificate, the seller-applicant,

> Unconditionally agree[d] to (1) waive all rights to seek future rate increases under section 4 of the Natural Gas Act with respect to the contract submitted, other than price escalations, if any, as certificated by the Commission; and (2) waive[d] all rights to contingent adjustment of flowing gas rates as provided by the Commission in area rate decisions heretofore decided, for flowing gas which the seller-applicant produces in the same geographical pricing area as the pricing areas of the production covered under this section. (§ 2.75(m) (1979))

Optional pricing was inaugurated to serve the twofold purpose of certificating sales of gas not previously deliverable to the interstate market at prices which are shown to be in the public interest while, to the extent possible, lessening rate uncertainty.[24] The optional procedure was not intended to supersede the procedures of areawide or nationwide rate proceedings;[25] it was an alternative to these proceedings available if a producer was willing to forego the benefits of areawide or nationwide proceedings in exchange for the certainty of a certificated rate.[26] The price of that certainty, and the higher rate that went with it, was the acceptance of the waiver condition quoted above.

The operative presumption of those who argue that waiver under the NGA should not and cannot be construed as a waiver for purposes of the NGPA is that the NGPA supplanted the provisions of certificates granted under the NGA. This is decidedly not so. The ability of the seller of gas certificated under the optional procedure to charge and collect rates is circumscribed by not only the provisions of any contract, but also the provisions of the certificate issued under the NGA.

Natural gas which is "committed or dedicated to interstate commerce" on November 8, 1978, remains subject to the Commission's full NGA authority unless the natural gas is finally determined to be high-cost natural gas (as defined in section 107(c)(1) through (4) of the NGPA), new natural gas (as defined in section 102(c) of the NGPA), or natural gas produced from any new, onshore production well (as defined in section 103(c) of the NGPA). This follows from the provisions of section 601(a)(1)(B) of the NGPA and its reference to section 1(b) of the NGA.[27] Thus, for natural gas which was "committed or dedicated to interstate commerce" on November 8, 1978, and priced under sections 104 and 106 of the NGPA, the certificate obligations agreed to by the holder and the other requirements of the NGA (particularly those of section 4) continue unaffected by the passage of the NGPA. The Commission has recognized this interaction of the NGPA and the NGA in producer filing requirements issued under the NGPA.[28]

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[22] *FPC* v. *Moss*, 424 U.S. 494 (1976); *Tenneco Oil Co.* v. *FERC* 571 F.2d 834 (5th Cir. 1978).

[23] 18 CFR § 2.75(b) (1979) (emphasis added). This language is tempered by § 2.75(d) which provides that the optional procedure will not limit the applicability of section 5 (NGA) proceedings.

[24] Order No. 455, note 21 *supra* at 3.

[25] *Id.* at 11.

[26] *Id.*

[27] Section 1(b) of the NGA sets forth the scope of that act and provides that the NGA "shall apply to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public

The seller of natural gas under an optional procedure certificate has waived "all rights to seek future rate increases under Section 4 of the Natural Gas Act with respect to the contract submitted, other than price escalation, if any, as certificated by the Commission" (18 CFR § 2.75(m)). The certificate is also not subject to change by "determinations or orders whether heretofore made or hereafter to be made in producer or pipeline rate proceedings initiated under section 4 of the Act" (18 CFR § 2.75(d)). These conditions are part and parcel of the certificate and of the Commission's determination that the "rates, charges, and services therein specified are just and reasonable, and required by the present and future public convenience and necessity" (18 CFR § 2.75(1)). Absent operation of section 601(a)(1)(B) of the NGPA, these conditions continue to govern the sale of gas by the certificate holder. Moreover, while the provisions of section 601(c)(1) preclude the Commission from prospectively denying or conditioning the grant of any certificate under section 7 of the NGA if the price paid in the sale is deemed to be just and reasonable, this provision in no way invalidates the terms and conditions related to rates in outstanding certificates. Given the provisions of section 601(c)(1) of the NGPA which indicate that Congress knew how to limit the Commission's conditioning authority in certificates on matters related to price, it follows that the conditions and other limitations in existing optional procedure certificates continue to govern the lawful price of these sales.

Since the seller of natural gas under a certificate issued under the optional procedure is precluded under that certificate from making a rate change filing in accordance with the requirements of section 4 of the NGA,[29] it may not collect any rate other than the rate which is specified in the contract and certificated by the Commission. The issue then is not whether optional rates established prior to April 20, 1977 are to be adjusted for inflation, but rather whether those holding such certificates may collect an NGPA inflation-adjusted rate in derogation of those certificates. We find that they cannot. The Commission, therefore, affirms the decision reached in the interim regulations as one supported by both the provisions of the NGA and the NGPA.

In affirming this decision, the Commission should be clearly understood as enforcing the terms of a certificate granted under the NGA. By

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consumption for domestic, commercial, industrial or any other use, and to natural gas companies engaged in such transportation or sale. . . ."

[28] *See, e.g.,* Order No. 15, "Amendments to the Commission's Regulations Relating to Independent Producer Filing Requirements," Docket No. RM79-4 (issued Nov. 17, 1978), 43 FR 55756 (Nov. 29, 1978), *as modified,* Order No. 15-A (issued Dec. 28, 1978); Order No. 25, "Amendments to the Commission's Regulations Relating to Independent Producer Filing Requirements," Docket No. RM79-31 (issued Mar. 27, 1979), 44 FR 19367 (Apr. 3, 1979), *as clarified,* Order issued May 25, 1979.

In Order Nos. 15 and 15-A, the Commission referenced the thirty days notice requirements of the NGA. In Order No. 25, the Commission stated:

Since sections 104 and 106(a) of the NGPA cover gas which was committed or dedicated to the interstate market as of November 8, 1978, the rate change filing requirements of the Natural Gas Act continue to apply to such gas even though the price therefore is determined in accordance with the provisions of the NGPA.

Order No. 25 at 1-2. The Commission then discussed the effect of section 601(a)(1)(B) of the NGPA and concluded that the rate change filing requirements of the NGA continued to apply to committed or dedicated natural gas subject to sections 102(d) or 108 of the NGPA. *Id.* at 3-4.

[29] Moratoria on producer rate filings are valid under the Natural Gas Act. *Permian Basin Area Rate Cases,* 390 U.S. 747 (1968); *Southern Louisiana Area Rate Cases* v. *FPC,* 428 F.2d 407 (5th Cir. 1970).

virtue of section 601 of the NGPA, sales of natural gas priced under the provisions of section 103 and certain parts of sections 102 and 107 of the NGPA are not subject to the Commission's NGA jurisdiction. Therefore, in the event that one who sells under the obligation of an optional certificate receives a determination that the gas so sold is eligible for a ceiling rate under an NGPA section which is exempt from NGA jurisdiction, the new ceiling rate, as adjusted for inflation under the NGPA, applies. Alternately, a producer who is bound by the terms of an optional certificate and who is not selling the gas under the provisions of those sections of title I of the NGPA not subject to the NGA, may petition the Commission to amend the certificate so as to remove the waiver condition.

Finally, we would point out that this decision does not touch the definite price escalations contained in certificates granted under the optional procedure. Such escalations, and the right to collect them, are unaffected by our NGPA regulations.

One comment, filed to supplement an original comment, argued that the Commission has a policy that "regulations premised on a finding that they were required to protect the public interest should remain effective and bar the intent of the NGPA *only if* the Commission could determine that the regulation was still needed to protect that 'public interest'." (emphasis in original). In support of this view, the comment quoted the following passage of Commission Order No. 23:

> The continued viability and application of the rule [respecting price escalator clauses under § 154.93], therefore, would seem to turn on whether the Commission could successfully establish that it had a reasonable basis for concluding that a particular prohibited clause was contrary to the public interest.[30]

Without glossing Order No. 23, we disagree that the touchstone for considering optional prices under the NGPA is a determination, or more precisely a redetermination, of public interest.

Optional prices rest upon a finding that they are in the public interest for present and future sales. In confronting an analogous situation, that of determining whether optional prices set prior to nationwide rates should be increased to the nationwide rate, the Commission decided that optional prices should not be reconsidered in the light of general rate increases. This decision was upheld by the courts.[31] The same concern exists under the NGPA. To permit rates certificated under the optional pricing procedure to be increased by an NGPA inflation adjustment and to permit holders of optional certificates to file for that increase would accord holders of optional certificates the benefits of both optional pricing and NGPA pricing. It would (as discussed above) violate the very conditicns under which the prices were certificated—a wavier of the rate filings; this is a result which we believe is contrary to the intent of the NGPA.

One comment interpreted § 271.402(c)(3) as precluding the collection of rates set under § 2.75(o). Section 2.75(o) permits the interim collection of rates at a level no higher than applicable nationwide rates for a set period of time pending Commission consideration of contracts submitted under the optional pricing procedure. On December 1, 1978 the Commission issued its "Order with Respect to Pending Optional Procedure Cases" (Docket No. CI76-590, *et al.*). By that order the Commission provided that rates charged and collected under the provisions of § 2.75(o) are to be "no higher than the applicable maximum lawful price authorized under the NGPA and the Commission's implementing regulations with respect thereto." To the extent then that a seller is receiving an interim rate under § 2.75(o) which is equal to an areawide or nationwide rate, he therefore falls under the provisions of § 271.402(a).

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[30] Order No. 23, "Order Adopting Final Regulations Amending and Clarifying Regulations Under the Natural Gas Policy Act and the Natural Gas Act" at 27, Docket No. RM79-22 (issued March 13, 1979).

[31] *See, e.g., ECEE, Inc. v. FPC,* 526 F.2d 1270 (5th Cir. 1976).

c. Small producer pricing.—Several comments responded to the Commission's decision to maintain the distinction between small producers and large producers and to adjust the ceiling rate of small producer rollover contracts under the NGA rather than the NGPA. While most comments favored the retention of a small producer pricing category, a few argued for its elimination. Other comments sought a higher small producer ceiling rate for rollover contracts than was provided under the interim regulations.

Those who urged the elimination of the small producer pricing category, particularly from pricing under section 106 of the NGPA, argued that the NGPA failed to explicitly provide for small producers under section 106. The Commission's argument on the issuance of the interim regulations that this was a Congressional oversight was met with the response that the clear, unambiguous words of section 106(a)(2) make no distinction between small and large producers and that the proper cure for an inadvertent omission in a statute is Congressional amendment.

The Commission adheres to its decision to maintain the small producer category for purposes of pricing under sections 104 and 106 of the NGPA. While it is true that the NGPA does not explicitly cite to such a category, we believe that such a distinction is necessary to carry out the intent of the Act.

Section 104 clearly references rates set by the Commission prior to the NGPA; and a rate for small producers was among those rates.[33] A narrow reading of section 106 would have us either read small producer rates out of section 104 or provide for such rates under section 104 and ignore them, or set a price less than they would have received under the NGA, when they rolled over. We do not believe that either course of action was contemplated by the Congress for this interstate market.

Given that the small producer category should be available for section 104 of the NGPA, the second issue raised by the comments was: What price should obtain for this category under sections 104 and 106? Under the provisions of section 104, that a ceiling price should be the just and reasonable rate applicable on April 1977 adjusted for inflation, the Commission set a price (as of December 1978) for section 104 small-producer gas pegged to 130% of prices accorded large producers. That price would be adjusted monthly for inflation as required under section 104. The calculations used to arrive at that price were straightforward; the then current NGA rate (as set by Opinion 770) was used for the April 1977 initial rate and multiplied by 1.30 (the equivalent of the small producer differential), and then adjusted for inflation.

For section 106 of the NGPA the Commission considered, and the comments advanced, several options. The options stem from the words of section 106(a) and its use of a 54-cent initial (April 1977) price. Following the literal words of section 106(a) would result in a December 1978 small producer price of 60.3 cents (a procedure used to set the large producer rollover rates). To adopt this as a ceiling rate would allow small producers whose contract rolled over a ceiling price less than what they would have received had the NGPA not been passed and they would have been priced under NGA replacement contract provisions. Alternatively, the price for section 106 small producers could be set equal to the price permitted them under section 104 for replacement contracts; that is, a December 1978 price of 77.1 cents adjusted monthly thereafter for inflation.

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[33] *See, e.g.*, Opinion 770–A, "National Rates for Jurisdictional Sales of Natural Gas Dedicated to Interstate Commerce on or after January 1, 1973, for the Period January 1, 1975, to December 31, 1976," at 134, Docket No. RM75–14 (issued Nov. 5, 1976).

(Comments on this alternative were expressly solicited.) This alternative would continue the small producer-large producer distinction for rollovers. Finally, as adopted in the interim regulations, the price could be calculated by taking the NGA rate of 54 cents for 1978 and multiplying it by 1.30 (the small producer differential). The resulting price (70.2 cents for December 1978) would then increase, as stipulated under NGA provisions (Opinions 770 and 742) by 1.3 cents per year until the ceiling equaled that set for large producers under section 106(a) of the NGPA, at which time the small and large producer distinction would disappear and but one ceiling price would apply to both.[33]

The Commission's action in adopting the third alternative rested on its authority, under section 106(c) of the NGPA, to set a price by rule or order if such price was "just and reasonable" within the meaning of the NGA and higher than that accorded by section 106(a). This action was criticized by two comments which argued that to set a just and reasonable rate in this manner the Commission must first ascertain whether any differential between small and large producers was warranted and, if so, how much that differential should be. We disagree. The level of the rate has, under the NGA, already been determined as just and reasonable.

Three comments argued that the clear words of section 106(a) of the NGPA require that the rate set under that section for all producers, including small producers, must be increased by the NGPA inflation factor and not the NGA yearly adjustment of 1.3 cents. One of the three argued that the price should be equal to the one computed for large producer sales under rollover contracts; the other two argued that the price should be increased over that set in the interim regulations by either (1) using a 54-cent initial rate times 1.30 and adjusting for inflation from April 1977 to December 1978 and thereafter, or (2) applying the 1.30 differential to the December 1978 large producer rate of 60.3 cents, and then adjusting the result by the NGPA inflation factor. A fourth comment, which can be read as arguing for the NGPA inflation adjustment, advocated the alternative suggested but not adopted by the Commission, that the price be equal to the price permitted small producers under section 104 for replacement contract gas. The Commission rejects all of these alternatives.

Section 106 of the NGPA does not provide for a distinction between small and large producers. Moreover, that NGA distinction (the 130 percent increase for small producers) makes little sense under the pricing provisions of section 106. The provision that small producers should receive a rate 130 percent greater than that accorded other producers is premised upon their receiving 130 percent of a rate which, by section 106 of the NGPA, is supplanted. Yet if the price of section 106(a) were to be applied to small and large producers alike, the result would be a price less than what small producers would have received had the NGPA not been passed. The problem then is one of establishing a pricing mechanism under section 106 for small producers which at once conforms to the intent of section 106 without imposing undue harm on those producers.

The interim regulations created a transitional solution. Small producer rollover contracts are permitted a ceiling price which would be, at least initially, equal to what they would have received under the NGA; and they would continue to have that ceiling established by the NGA formula until such time as the price of section 106(a) caught up to that price. In this way, the small producer does not suffer harm during the first few years that the NGPA is in effect; and the small producer is considered under the statutory provisions of section 106—for the transition period the ceiling is set under the Commission's section 106(c) authority to prescribe a higher rate; after that period the ceiling is one set under section 106(a).

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[33] Current staff estimates show that this point could be reached by mid-1982.

The alternatives offered by the comments and suggested in the Commission's December 1, 1978 preamble suffer from one of two major drawbacks. Either they provide a ceiling rate which is lower than the one prescribed under the NGA for small producers or, (by increasing rates by the NGPA inflation adjustment) they perpetuate a distinction no longer tenable under section 106 of the NGPA.

The rate of 70.2 cents for small producers pricing under section 106(c) of the NGPA, increased by the yearly adjustments provided under Opinions Nos. 770, *et seq.* and 742, *et seq.*, is, in our opinion, a just and reasonable rate. It is a rate based upon the NGA base of 54 cents (as of 1978), and it is increased by the small producer differential (established in prior opinions of the Commission under the NGA) and adjusted by the yearly adjustment established for small producer rates under those opinions. It is used to prevent a small producer from receiving a rate under section 106(a) of the NGPA which would be lower than that to which the producer would be entitled to under the NGA. For these reasons, the small producer rollover ceiling of 70.2 cents (December 1978) adjusted by 1.3 cents per year meets the criteria set out under section 106(c) of the NGPA.

d. The one-cent differential.—Section 106(a) of the NGPA provides that the initial rate upon which a ceiling rate for first sales of committed or dedicated gas sold under rollover contracts is calculated is 54 cents. Therefore, if a contract rolls over after November 8, 1978, and thereby becomes subject to section 106(a), a ceiling price of 60.3 cents (as of December 1978) is permitted. If the contract rolled over before that date, however, it is a "replacement" contract and the lower price of section 104 applies (59.3 cents as of December 1978).

Several comments advocated a one-cent increase for replacement contract gas to eliminate this price difference. These comments argued that the one-cent differential results from a definition based on no material fact except the time of rollover. In further support of this view, they argued that the Congress could not have intended that replacement contracts be priced lower than rollover contracts, and that statutory language which permitted this result was an oversight and without foundation because it unduly discriminates against contracts which rolled over before November 9, 1978. To permit the distinction to continue would, to these comments, be to permit unreasonable results and wasteful administrative burdens. These comments urged the Commission to use its authority under section 104(b)(2) of the NGPA to adjust the replacement contract ceiling rate (the section 104 rate) upward by one cent.

One comment argued that no such change should be made. That comment argued that to eliminate the differential on the grounds that the distinction between replacement contract and rollover contract is based merely on an arbitrary date would set a dangerous precedent for the review of other distinctions drawn under the NGPA on the basis of dates.

The Commission finds that no change should be made in the regulations. To exercise its authority under section 104(b)(2) of the NGPA to provide a higher ceiling price, the Commission must find that the higher price is just and reasonable. In proposing to eliminate the one-cent differential and to treat replacement contracts the same as rollover contracts for purposes of establishing ceiling prices, the Commission therefore sought comments on whether the lower replacement rate was "unjust and unreasonable". Nothing submitted supports the conclusion that a price for replacement contracts equal to that of rollovers meets the test. In addition, we can find no justification that the increase would be "just and reasonable". Finally, and most importantly, the distinction between a replacement contract and a rollover contract is one specifically mandated by the NGPA. For these reasons we decline to exercise our discretion under section 104(b)(2) of the NGPA to set a higher section 104 ceiling price for replacement contract gas.

e. Other pricing issues.—Comments on Subpart D raised several other questions concerning the pricing of natural gas committed or dedicated to interstate commerce. Most of these comments were in the nature of requests for clarification.

The Office of Indian Affairs, Department of Energy, argued that Indian royalty gas taken "in kind" and sold on the interstate market should qualify for the rollover or replacement contract price irrespective of whether the prior contract has expired by its own terms. In justification, the comment argued that such royalties are "essentially public revenues" and that Congress expressly favored Indian gas in section 106(b)(2) of the NGPA. In addition, the Office of Indian Affairs cited to the court's opinion in *Jicarilla Apache Tribe* v. *FPC*, 578 F.2d 289 (10th Cir., 1978) for the proposition that an Indian tribe is not bound by large producer contract prices when taken "in kind."

While it is true that Congress has accorded special consideration to Indian gas under the provisions of the NGPA dealing with intrastate rollover contracts, it by no means follows that such treatment should be accorded sales under interstate rollovers or replacement contracts. The replacement contract concept was implemented under the prior NGA practice of the Commission. As with the NGPA concept of "rollover", a basic qualification for "replacement" was the termination of the prior contract by its own terms. The Commission declines to make an exception to this long-standing requirement. In addition, while the provisions of section 106(b)(2) are quite detailed and specific as to intrastate sales of Indian gas, similar treatment is not accorded for sales made under interstate contracts. To adopt the suggestion made by the comment would be to set up a special exception which is unwarranted by the NGPA.

The arguments that sales of Indian royalty gas are "in the nature of public revenues" and the reference to *Jicarilla* appear misplaced. The NGPA sets forth a general scheme for the regulation of first sales of natural gas. While there are several distinctions under the provisions of Title I of the NGPA, "public revenues" is not among them. More to the point, if we permitted a higher price for Indian royalty gas based upon such a concept, it follows that we should similarly price all gas under this theory because at least some of the proceeds of all first sales are in the nature of "public revenues," *i.e.* taxes.

Jicarilla stands for the proposition that producer sales of Indian royalty gas, like other producer sales of natural gas, are subject to Commission regulation. The precise holding of *Jicarilla,* alluded to in the comment, goes to the definition of "purchase" under § 157.40(c) of the Commission's regulations. In that case, the court held that the plaintiffs election to take royalty payments "in kind" rather than "in cash" was not a purchase under § 157.40(c) so as to preclude the royalty owners from taking advantage of the small producer pricing provisions.

Some comments sought clarification of Commission regulations under Subpart D of Part 271 regarding percent-of-sale contracts. These comments suggested that the regulations should make it clear that one who sells gas to a reseller under the terms of a percentage contract should receive the percentage of proceeds realized when the reseller's contract rolls over and the reseller receives a higher price under section 106(a) of the NGPA.

Neither section 104 nor section 106(a) of the NGPA specifically addresses the issue of pricing interstate percentage-sale contracts. Under the NGA, those who sold under a percentage-sale

contract were regulated by the expedient of regulating the subsequent seller. Under the NGPA, the subsequent seller is a reseller subject to the ceiling price requirements of the NGPA. Therefore, the same indirect regulation practiced under the NGA appears applicable under the NGPA through operation of the reseller regulations of § 270.202. Thus, the maximum lawful price will, for percentage-sales contracts, apply to the sale by the reseller. The full presentation of this position, as well as the necessary amendments to § 270.202 to carry out the position, will be made under final regulations implementing sections 105 and 106(b) of the NGPA.

One comment inquired whether certain escalation clauses of the settlement agreement approved under Docket No. RI75–21 (Independent Oil and Gas Associates of West Virginia, *et al.*, settled March 22, 1976) now authorize producers subject to that settlement to collect statutory rates provided under the NGPA. An intermediate decision on this issue has been rendered and that decision is now before the Commission on briefs on exceptions and briefs opposing exceptions.[24] A decision on this issue must therefore await action on those briefs.

One comment questioned whether the NGPA section 104 price applies to a "successor" to an existing interstate contract. The short answer to this question is, yes. A successor to an existing contract is defined under section 2(14) of the NGPA as "any contract *other than a rollover contract*, entered into on or after the date of the enactment of this Act, for the first sale of natural gas which was previously subject to an existing contract whether or not there is an identity of parties or terms with those of such existing contract" (emphasis added). Section 106 of the NGPA referencing as it does prices for "rollover," is clearly inapplicable. Sections 102 and 103 are also inapplicable because they concern "new gas" production. Section 105, which does specifically reference "successor" contract natural gas, does so only in the context of intrastate sales. Finally, section 109 does not apply because it references natural gas sales for new gas not otherwise covered, or for natural gas not priced by contract or Commission action before November 8, 1978.[25] Thus, the proper price for successor contracts for natural gas committed or dedicated to interstate commerce for which a price was in effect on November 8, 1978 is the price stipulated in section 104 of the NGPA.[26]

One comment sought clarification of the term "established" as used in § 271.402(c)(2). That comment argued that a just and reasonable rate established under special relief procedures is "established" by the Commission at the time that it may actually be collected or, alternatively, at the time when the circumstances which warranted the special relief rate occurred. Adopting the views of this comment would permit a particular special relief price approved after April 20, 1977, but prior to November 9, 1978, to escape the noninflation adjustment provisions of § 271.402(c)(2) (and, parenthetically, the clear provisions of section 104(b)(1)(B) of the NGPA). This we decline to do.

For purposes of § 271.402(c)(2), a rate is established on the date the Commission issues an order authorizing the collection of the rate. If such an order was issued after April 20, 1977 but before November 9, 1978, that rate, unadjusted for inflation, may be collected if it is higher than a rate defined under § 270.402(a).

Finally, one comment, citing to the Commission's regulation respecting pipeline production under the NGPA

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[24] Docket No. RI74–188.

[25] Section 109 also stipulates a price for natural gas produced at Prudhoe Bay for transportation through the Alaska Natural Gas Transportation System.

[26] Sections 107 and 108 of the NGPA, being special pricing provisions, do not apply to the instant question.

(§ 270.203) and reading the same as excluding the first sale of such production from "first sales" under the NGPA, argued that the effect of § 270.203 is to deny interstate pipelines the "parity of price treatment with independent producers under section 104 of the NGPA with respect to 'old natural gas' produced from wells drilled before January 1, 1973, or leases acquired before October 8, 1979 . . ." Consideration of this issue, and the definition of pipeline production within first sale pricing provisions of Title I of the NGPA, is best left to Commission consideration of § 270.203.[37]

3. Definitions

The definitions of § 271.402(b) received very little comment. Those comments that were received dealt with the definitions of small producer sales and replacement contracts.

Two comments suggested that the term "small producer sales" should be defined by reference to the level of sales made in the intrastate market as well as the interstate market. In support of this suggestion, the comments argued that it was inappropriate to continue the prior practice (under the NGA) of considering only interstate sales in defining small producers when the applicable statute, the NGPA, did not so distinguish small producers. The Commission rejects that suggestion.

The provisions of section 104(a) of the NGPA speak to just and reasonable rates as of April 1977. Among these rates were the rates which applied to "small producers". These producers were defined with respect to interstate sales. In addition, the rates established under the regulations implementing section 104 of the NGPA reference rates set under the NGA. Expanding the definition of small producers to include intrastate sales would inaugurate a pricing scheme which, contrary to section 104, does not reference rates set under the NGA. Accordingly, the Commission will not adopt this proposal. Furthermore, to include intrastate sales in defining a "small producer" would unnecessarily complicate the pricing provisions of Subpart D.

One comment suggested that the definition of replacement contract be amended in § 271.402(b)(4)(iv) by the addition of the words "in the same well' after the phrase "produced as a result of a completion operation into a different formerly nonproductive reservoir, commenced on or after January 1, 1973, and produced through a well commenced prior to January 1, 1973." This suggestion is rejected. We see no need to modify this definition at this time, and no rationale has been offered in support of such a change.

4. Procedures

One comment suggested that procedures be inaugurated to amend § 2.75 of the Commission's regulations (dealing with optional pricing procedures) so that those procedures would not apply to sales made on or after November 9, 1978. The rationale offered for such an amendment was that the NGPA mooted the procedures of § 2.75. With respect to applications pending under § 2.75, the same comment suggested that such gas be priced under the provisions of section 104(b)(2) of the NGPA at a ceiling rate equal to the interim rate at which the gas was being sold.

Since the issuance of interim regulations for Subpart D, the Commission has issued a notice of proposed rulemaking under Docket No. RM79-67 to specifically consider procedures for special relief under the NGPA.[38] Procedures to amend § 2.75 will be considered under that rulemaking.

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[37] Order No. 58, "Final Rule Governing the Maximum Lawful Price for Pipeline, Distributor or Affiliate Production," Docket No. RM80-7 (issued Nov. 14, 1979); Notice of Proposed Rulemaking, "Pricing of Pipeline and Affiliate Production Under the Natural Gas Act," Docket No. RM80-6 (issued Nov. 14, 1979).

[38] "Procedures Governing Applications for Special Relief Under Sections 104, 106, and 108 of the Natural Gas Policy Act of 1978," Docket No. RM79-67 (issued Aug. 14, 1979), 44 FR 49468 (Aug. 23, 1979).

That the procedures of § 2.75 do not apply to sales made on or after November 9, 1978, is a necessary result of the NGPA. For those who were exercising the option of § 2.75(o), the price is one which, because it is equal to or less than the applicable nationwide rate, should be treated under section 104 of the NGPA. Yet this rate cannot be set under section 104(b)(2); because there has been no finding that such rate, as between the stated parties, is "just and reasonable". Instead, it is more properly considered under the provisions of section 104(a) of the NGPA and § 271.402(a).

A second comment advocated that the Commission amend its procedures under § 271.402(c)(3) to provide for public notice and an opportunity for interested persons to be heard on special relief applications. This issue is also addressed under Docket No. RM79–67.

Finally, the Public Service Commission of the State of New York requested that the Commission require more information on filings made to collect prices under sections 104 and 106(a). This comment advocated that adequate contract information and contract authority for charged prices should be required. This issue has, we believe, already been properly addressed under Order Nos. 15, 15–A and 25. (*See*, note 28 *supra*.)

C. Public Procedures and Effective Date

The regulations of Subpart D, Part 271 were originally proposed for comment in November of 1978, and issued as interim regulations on December 1, 1978 (43 FR 56448, *et seq.* (Dec. 1, 1978)). For 60 days thereafter comments were received and during that period public hearings were held on these interim regulations. By this process the Commission complied with the provisions of section 553 of Title 5 and also with section 502(b) of the NGPA which requires that "[t]o the maximum extent practicable," an opportunity for the oral presentation of data, views, and arguments be afforded for certain regulations under the NGPA.

The interim regulations comprising Subpart D of Part 271 are being reissued as final regulations without amendment or revision. Accordingly, the Commission finds that further notice and public procedure on these rules is unnecessary and impractical and that good cause exists to dispense with additional notice and comment procedures, and to make Part 271, Subpart D, effective immediately as final regulations.

(Natural Gas Act, as amended, 15 U.S.C. 717, *et seq.*; Natural Gas Policy Act of 1978, Pub. L. 95–621, 92 Stat. 33650, 15 U.S.C. §§ 3301 to 3432; Department of Energy Organization Act, Pub. L. 95–91, E.O. 12009, 42 Fed. Reg. 46267.)

In consideration of the foregoing, Subpart D, Part 271 of the Commission's interim regulations are hereby reissued as final regulations as set forth below, effective immediately.

By the Commission. Commissioner Sheldon voted present.

Kenneth F. Plumb,
Secretary.

[¶ 30,117]

45 F. R. 1872 (January 9, 1980)

18 CFR Part 282

[Docket No. RM79-21]

Rule Exempting Industrial Boiler Fuel Facilities From Incremental Pricing Above the Price of No. 6 Fuel Oil; Notice of Effective Date

January 3, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of effective date.

SUMMARY: On September 28, 1978, the Federal Energy Regulatory Commission (Commission) issued a rule providing an exemption to industrial boiler fuel facilities from being priced above the price of high sulphur No. 6 fuel oil during the first ten months of the incremental pricing program. The rule was later transmitted to Congress for review as required by section 206(d) of the Natural Gas Policy Act of 1978. During the period for Congressional review, neither House disapproved the submittal. The exemptive rule thus became effective December 1, 1979.

EFFECTIVE DATE: December 1, 1979.

FOR FURTHER INFORMATION CONTACT: Barbara K. Christin, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8079.

SUPPLEMENTARY INFORMATION: On September 28, 1979, the Federal Energy Regulatory Commission (Commission) issued final rules in Docket No. RM79-14 and Docket No. RM79-21 which implement the first phase of the incremental pricing program mandated by the Natural Gas Policy Act of 1978 (NGPA). The regulations in Docket No. RM79-21 set ceilings on the prices which can be charged to large industrial facilities for their use of natural gas as a boiler fuel.

Order No. 50, issued in Docket No. RM79-21, sets forth a three-tier approach for the determination of the ceiling prices to be charged. Under this approach, large boiler facilities are required to pay a price for their natural gas equivalent to the price they would pay for the fuel oil which they could burn as an alternate to natural gas.

Order No. 51 was issued as a companion "Final Rule" to Order No. 50. Order No. 51 amends the regulations contained in Order No. 50 to provide that, for the period January 1, 1980, until November 1, 1980, each industrial boiler fuel facility not otherwise exempted from the program shall be exempt from incremental pricing above the level of the price of No. 6 high sulphur fuel oil in the incremental pricing region in which the facility is located.

The regulations contained in Order No. 51 were promulgated by the Commission under the authority of section 206(d) of the NGPA. Under that section, the Commission may, by rule or order, exempt, in whole or in part, individual industrial facilities or categories of such facilities from the incremental pricing program. In accordance with the provisions of section 206(d), the regulations could take effect following 30 calendar days of continuous session of Congress (as defined in section 507(b) of the NGPA) unless either House adopted a resolution of disapproval within that 30 day period.

Order No. 51 was submitted to both Houses of Congress on October 10, 1979. The Congressional review period thus expired on November 9, 1979. Congress took no action on Order No. 51 during the review period. Therefore, Order No. 51 became effective December 1, 1979, the effective date provided for in the rule.

Kenneth F. Plumb,

Secretary.

[¶ 30,118]

45 F. R. 1872 (January 9, 1980)

18 CFR Part 284

[Docket No. RM79-24; Order No. 63]

Certain Transportation, Sales and Assignments by Pipeline Companies not Subject to Commission Jurisdiction Under Section 1 (c) of the Natural Gas Act

Issued January 3, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: This final rule presents the Commission's view that natural gas pipelines which are exempt from the Commission's jurisdiction under Section 1(c) of the Natural Gas Act (Hinshaw pipeline) fall within the Natural Gas Policy Act's definition of local distribution companies.

The final rule permits Hinshaw pipelines to apply for a blanket section 7(c) certificate authority to sell and transport natural gas in interstate commerce and assign contractual rights to natural gas under the same conditions as apply to those transactions when engaged in by intrastate pipelines under sections 311 and 312 of the Natural Gas Policy Act of 1978.

The final rule is intended to further implement the Commission's policy of integrating the interstate and intrastate natural gas markets, removing administrative burdens from the sale of natural gas, and improving consumer access to natural gas.

EFFECTIVE DATE: January 3, 1980.

FOR FURTHER INFORMATION CONTACT:

Robert C. Platt, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8454.

Robert J. Cupina, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-9031.

I. Background

The Federal Energy Regulatory Commission (Commission) is issuing a final rule which would permit pipeline companies with facilities excluded from Commission jurisdiction pursuant to section 1(c) of the Natural Gas Act (hereinafter referred to as "Hinshaw pipelines") to apply for certain blanket certificate authority pursuant to section 7(c) of the Natural Gas Act. Any such certificate issued pursuant to section 7(c) of the Natural Gas Act would permit the transportation and sale of natural gas in interstate commerce and the assignment of contractual rights to natural gas under the same conditions as those activities are permitted to be engaged in by intrastate pipelines under sections 311 and 312 of the Natural Gas Policy Act of 1978 (NGPA).

The Commission's final rule is based upon consideration of 21 written comments [1] received in response to the July 2, 1979 Notice of Proposed Rulemaking [2] as well as the public hearing convened on July 30, 1979.

II. Discussion

An important objective of the NGPA is to remove artificial restraints on the flow of gas between the interstate and the intrastate market. As part of its effort to reach this objective, Congress adopted sections 311 and 312 of the NGPA. Those sections permit the Commission to authorize intrastate pipelines to transport, sell, or assign natural gas to the interstate market. However, since only intrastate pipelines may transport natural gas under section 311(a)(2), sell natural gas under section 311(b) or assign natural gas under section 312(a), the effectiveness of those provisions, as well as the effectiveness of the policies which they implement, are dependent to a significant degree on the definition of an intrastate pipeline.

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[1] Late supplemental comments filed by Peoples Natural Gas Division of Northern Natural Gas Company on September 12, 1979, and by Oklahoma Natural Gas Company on August 29, 1979 were also considered.

[2] 44 FR 40072 (July 9, 1979).

Section 2(16) of the NGPA defines "intrastate pipeline" as follows:

> (16) Intrastate Pipeline.—The term intrastate pipeline means any person engaged in natural gas transportation (not including gathering) which is not subject to the jurisdiction of the Commission under the Natural Gas Act (other than any such pipeline which is not subject to the jurisdiction of the Commission solely by reason of section 1(c) of the Natural Gas Act).

The Commission believes that the NGPA requires that all Hinshaw pipelines be classified as local distribution companies. The Statement of Managers explains that such pipelines are so classified in order to insure that they will be subject to incremental pricing.[3]

The effectiveness of NGPA sections 311 and 312, dealing with certain transportation and sales of natural gas and assignments by intrastate pipelines, is diminished by the determination that a pipeline holding a section 1(c) exemption is to be treated as a local distribution company (as defined in section 2(17) of the NGPA), since transportation services, sales and assignments may be made under NGPA sections 311(a)(2), 311(b) and 312 only by intrastate pipelines. However, classifying a Hinshaw pipeline as a local distribution company would preserve that company's ability to buy natural gas under section 311(b) or receive assigned gas under section 312.

The final rule establishes a blanket certificate procedure permitting Hinshaw pipelines to carry out transactions of the kind permitted by NGPA sections 311 and 312. The effect of the final rule would be to permit Hinshaw pipelines to provide transportation service, make sales, and assign contractual rights to natural gas quickly and without confusion as to the extent of any possible authority under NGPA section 311 and 312.

An example should clarify the rule. A pipeline company operates in a producing state, but it also receives, under a section 1(c) exemption, natural gas from an interstate pipeline. In order to permit the company to engage in sales and transportation of the kind authorized by NGPA sections 311 and 312, the final rule would allow the company to apply for one-time blanket authorization pursuant to section 7(c) permitting, in effect, transportation, sales, and assignments of natural gas in interstate commerce similar to that permitted by NGPA sections 311 and 312 for intrastate pipelines. In this way, the company as a whole would be able freely to transport and sell natural gas and to assign contractual rights to natural gas. This would be true even if the scope of the section 1(c) exemption was uncertain.

III. Analysis of Comments

A. Status of Hinshaw Pipelines

The Commission continues to maintain its view that all Hinshaw pipelines are local distribution companies within the meaning of section 2(17) of the NGPA. Some comments advanced the view that a Hinshaw pipeline which transports natural gas in interstate commerce through only a small segment of its total facilities should be deemed to be an intrastate pipeline with respect to the facilities which do not transport gas received from interstate sources. These comments suggest that a single corporation could have multiple classifications under the NGPA by satisfying both the section 2(16) and 2(17) definitions. However, the definition of "local distribution company" contained in section 2(17) of the NGPA excludes any "person" which is an interstate pipeline or an intrastate pipeline. Because the entire corporation is a "person", it appears that the entire corporation must be classified as a local distribution company even if a declaration of exemption is limited to only a portion of its facilities. Hence, the NGPA definitions apparently require a Hinshaw pipeline to form separate corporations for its Hinshaw and non-Hinshaw facilities in order to maintain both "local distribution company" and "intrastate pipeline" status under the NGPA. However, the final rule eliminates any practical reason for such corporate reorganizations. Because the blanket certificate permits a Hinshaw pipeline to participate in section 311 and 312 type transactions on the same basis as intrastate pipelines, the Hinshaw pipeline is not disadvantaged by being classified as a local distribution company in its entirety. Such a classification has the advantage of permitting the Hinshaw pipeline to purchase natural gas from intrastate pipelines under sections 311(b) and 312, which would not be permitted if Hinshaw pipelines were classified as intrastate pipelines.

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[3] H.R. Report No. 95–1752, 95th Cong. 2nd Sess. (1978) at 70, 96.

Other comments question the status of pipelines which hold declarations of exemption under section 1(c) of the Natural Gas Act, but which no longer engage in any transactions that require an exemption. The Commission views pipelines holding unnecessary declarations of exemption to be local distribution companies. However, any Hinshaw pipeline seeking to change its status may file a statement under § 152.5 of this chapter informing the Commission that its Hinshaw exemption is no longer applicable.[4]

B. Limitations upon Authorizations

Two comments question the desirability of conditioning sales made under the blanket certificate upon compliance with the price ceiling prescribed by Section 311(b) of the NGPA. The proposed rule incorporated the weighted average acquisition cost test of section 311(b) and § 284.143. Alabama Gas Corporation recommends that only the cost of intrastate supplies be included in computing the average costs.[5] However, to permit Hinshaw pipelines to base their price ceilings upon an average price that reflects only a portion of their cost supplies would be inconsistent with the basic intent of the final rule; Hinshaw pipelines will make sales under the blanket certificate under the same terms that apply to intrastate pipelines making sales under sections 311(b) of the NGPA.

The second comment questions the applicability of the transportation allowance specified in § 284.144(a)(3) to Hinshaw pipelines. Under § 284.144(a)(3) the costs of gathering, treatment, processing, transportation, delivery or similar service (including storage service) are included as part of the section 311(b) sales price ceiling. However, Michigan Consolidated Gas Company (MCGC) suggests that Hinshaw pipelines should also be able to include distribution costs as a part of the transportation allowance. MCGC notes that the Michigan Public Service Commission permits MCGC to recover these costs in intrastate sales made to other distributors. However, because distribution costs are not incurred in making sales under the blanket certificate, these costs are not recoverable under the final rule. Nor are distribution costs recoverable in a transportation rate established under § 284.123(b).

The Commission acknowledges that many Hinshaw pipelines, including MCGC, have no state approved city-gate tariffs. As a result, a state agency may not have had an occasion to approve an allocation of such a Hinshaw pipeline's costs between those permitted under § 284.123(b) and their distribution activities. Hinshaw pipelines without state approved city-gate tariffs are not eligible to elect either of the usual methods for establishing a rate specified in § 284.123(b)(1). Instead, such a Hinshaw pipeline may elect to have its methodology approved under § 284.222(e)(2) at the time its blanket certificate is issued which would permit its rates for individual transactions to be reviewed under § 284.123(b)(1). Such one-time approval of the rate methodology allows the Hinshaw pipeline to avoid seeking approval of rates in each individual transaction under the procedure specified in § 284.123(b)(2).

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[4] Even in situations where no related abandonment is involved, § 152.5 requires a Hinshaw pipeline to notify the Commission of any operational changes which make the section 1(c) exemption inapplicable to it. *United Texas Transmission Company*, Docket No. CP79-241, order issued August 10, 1979 at 4.

[5] The base rate for selling natural gas depends upon the actual weighted average acquisition cost under § 284.144(a). However, if the Hinshaw pipeline were to sell natural gas which is 1) in excess of quantities otherwise acquired under an existing contract, and 2) those quantities were obtained at a price above the Hinshaw pipeline's average cost, then the Hinshaw pipeline could charge a higher "adjusted" price under § 284.144(b).

The proposed rule limited the volume of natural gas sold under a blanket certificate to the volumes obtained from intrastate sources. Montana Power Company requests that the volumes obtained from foreign sources be considered equivalent to intrastate sources when applying this volumetric test. We agree. The purpose of the volumetric test is to prevent Hinshaw pipelines from selling a greater volume of natural gas in interstate commerce than the pipeline receives from its intrastate supplies. Such a requirement is consistent with the scope of the section 1(c) exemption. Because foreign commerce is not considered a part of interstate commerce within the meaning of the Natural Gas Act,[6] the final rule treats foreign sources on a par with intrastate sources.

Some comments advocate an exemptive rule under section 7(c)(1)(B) of the Natural Gas Act in lieu of a blanket certificate program. The Commission prefers to use blanket certificates because the transactions permitted under the final rule may not meet the "temporary acts or operations" statutory standard of section 7(c)(1)(B).

C. Statutory Provisions Applicable to Section 311 Transactions

Several comments request that the blanket certificates incorporate the statutory protections afforded to intrastate pipelines by sections 314 and 602 of the NGPA. Section 314 renders certain anti-commingling clauses in gas purchase contracts unenforceable. Because section 314 applies to the sale of any natural gas which is not "committed or dedicated to interstate commerce," section 314 covers all sales of such natural gas under the blanket certificate.[7]

Section 602(b) of the NGPA provides,

> No person shall be subject to regulation as a common carrier under any provision of Federal or State law by reason of any transportation . . . authorized by the Commission under Section 311(a) of this Act.

Because section 602(b) is limited to only section 311(a) transportation, the Commission cannot extend section 602 to cover transportation authorized by the blanket certificate and section 7(c) of the Natural Gas Act. However, in the Commission's view, the blanket certificate would preempt any state law which would impose a common carrier obligation upon a Hinshaw pipeline as a result of transportation rendered under its blanket certificate.

Mississippi Valley Gas Company questions whether natural gas which is not otherwise "committed or dedicated to interstate commerce" would fall within that definition by reason of being sold under a blanket certificate. Because the NGPA applies the definition of "committed or dedicated" as of two measuring dates, April 20, 1977 and November 8, 1978, transactions under a blanket certificate cannot possibly result in natural gas becoming "committed or dedicated."

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[6] *Border Pipe Line Company* v. *FPC*, 171 F.2d 149 (D.C. Cir. 1948), *Distrigas Corporation* v. *FPC*, 495 F.2d 1057 (D.C. Cir 1974).

[7] See § 270.206 of this chapter.

D. Incremental Pricing Undertaking

Section 284.222(e)(2) of the final rule requires a Hinshaw pipeline making a sale under a blanket certificate to obtain an undertaking from each buyer. Oklahoma Natural Gas Company seeks guidance on the text of the undertaking, questions the certificate holder's duty to enforce the undertaking, and suggests a provision which would keep in effect both the blanket certificate and the specific sale regardless of any breach of the undertaking. The Commission wishes to leave sellers with some discretion in drafting the text of the undertaking. The undertaking should state that the buyer agrees to credit to its incremental pricing account (Account 192) the amount that would have been credited pursuant to section 203(a)(10) of the NGPA had the sale been made by an intrastate pipeline. Also, the buyer should agree to abide by the rules and orders of the Commission concerning incremental pricing, and the undertaking should acknowledge the right of the Commission to enforce the undertaking.

The Commission intends to monitor these undertakings as an integral part of its implementetion of Title II of the NGPA. Should the Commission find that a purchaser is violating the provisions of the undertaking, the Commission reserves the right to order the termination of the sale or to rescind the blanket certificate, when warranted.

E. Other Hinshaw Pipeline Rules

Some comments request Commission action on matters which are outside the scope of the Notice of Proposed Rulemaking. Accordingly, the Commission will not take action in this docket upon suggested changes to: Subpart C of Part 157, Part 276 reporting requirements or budget type construction certificates under § 157.7 of this chapter. The Commission issued a final rule providing for construction of facilities to implement Part 284 transactions in Docket Nos. RM79–037 and RM79–43, on November 1, 1979.

IV. Section-by-Section Analysis

Paragraph (a) limits the blanket certificate to only Hinshaw pipelines. A suggested amendment to paragraph (a) which would have codified the Commission's classification of Hinshaw pipelines as local distribution companies was not adopted because the Commission's views are adequately expressed in this order.

Paragraph (b) indicates the limited nature of the blanket certificate. The certificate covers only sales and transportation services which are within the Commission's jurisidiction under the Natural Gas Act as transportation in interstate commerce or sales for resale in interstate commerce. Although the duration of any certificate will depend upon the term requested in the application, individual self-implementing transactions under the certificate are limited to two years by Subparts C, D and E of Part 284.

National Gas and Oil Company suggests modifying paragraph (b) to permit Hinshaw pipelines to participate as intrastate pipelines for all purposes in fuel oil displacement transactions authorized by Subpart F. Order No. 30-A amends Subpart F to permit Hinshaw pipelines to participate as local distribution companies when making sales under Subpart F.[6] In addition, Paragraph (b) of the final rule has been modified to permit Hinshaw pipelines to engage in transportation under the blanket certificate to the extent authorized by § 284.203.

Paragraph (c) prescribes an abbreviated application procedure. Because data on individual transactions will be filed within 48 hours of the commencement of each transaction, detailed data is not required for the blanket certificate application.

Hinshaw pipelines making application for a blanket certificate should state a method for calculating the rates to be charged which is permitted by NGPA sections 311 and 312. In this regard, system weighted average acquisition cost with respect to any sale under NGPA section 311(b) should not separate the cost of intrastate gas from interstate gas acquired pursuant to an exemption under NGA section 1(c).

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[6] Issued September 12, 1979, 44 FR 54472 (September 20, 1979).

Paragraph (d) specifies that the blanket certificate will not otherwise affect a Hinshaw pipeline's already exempt status. Similarly, compliance with the Commission's Uniform System of Accounts and general reporting requirements, other than those required by NGPA sections 311 and 312 and the Regulations thereunder would be waived.

Paragraph (e) prescribes the terms and conditions which would be contained in these certificates as being only those necessary to meet the statutory requirements of sections 311 and 312 of the NGPA and section 7(c) of the Natural Gas Act. These terms and conditions, relating to Part 284, would not embody the regulations which generally apply to natural gas companies subject to the Commission's jurisdiction under the Natural Gas Act. The Commission does not contemplate the need to include such Natural Gas Act requirements in the blanket certificates.

Certificate conditions will require that all volumes sold pursuant to the blanket certificate (1) shall be subject to incremental pricing to the same extent as if the sale had been authorized by section 311(b) of the NGPA,[9] and (2) shall not exceed the volumes obtained from sources other than interstate supplies.

The incremental pricing requirement in paragraph (e)(3) is necessary to conform to the intent of Title II of the NGPA. The NGPA requires that certain volumes sold under Title III shall be incrementally priced by the buyer. If the blanket certificate did not contain such a condition, then the legislative intent to incrementally price natural gas flowing in interstate commerce may not be achieved.

The volumetric requirement in paragraph (e)(4) is to prevent interstate supplies from being resold by the Hinshaw pipeline under terms appropriate for only non-interstate sources. Paragraph (e)(5) requires all filings pertaining to transactions authorized by the blanket certificate to reference the docket number in which the certificate was granted. Individual transactions may also have additional docket numbers assigned.

Paragraph (e)(6) has been added to clarify the manner in which a holder of a blanket certificate may comply with the tariff filing requirements of sections 4 (c) and (d) of the Natural Gas Act. The Hinshaw pipeline should file a complete copy of its contracts governing a transaction authorized by the blanket certificate as part of the 48-hour report required by § 284.4(b). Contract amendments must also be filed.

Paragraph (f) frees the holder of the blanket certificate from any service obligation after each underlying transportation contract expires. This pregranted abandonment places the holder of the blanket certificate in an equivalent position to a transporter authorized under section 311(a)(1) or 311(b) of the NGPA. Accordingly, the Commission finds that such abandonment is permitted by the present or future public convenience and necessity.

Several comments suggested that the Commission explicitly pregrant an abandonment contingent upon a final court ruling that the Commission exceeded its authority in issuing this order. The Commission considers such a provision unnecessary because the parties are free to include in their contract termination clauses covering any contingency of their choice.

Paragraph (g) prohibits a Hinshaw pipeline which does not have a blanket certificate from engaging as an intrastate pipeline in transactions otherwise authorized by Subparts, C, D,

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[9] See section 203(a)(10) of the NGPA.

E and F of Part 284. Paragraph (g) does not prohibit a Hinshaw pipeline from selling natural gas for fuel oil displacement under the terms specified by Subpart F for local distribution companies.

Paragraph (h) was added to remove the ambiguity concerning the meaning of the "pipeline company" used in the proposed rule. Any holder of a section 1(c) exemption that engages in the transportation of natural gas is eligible to apply for a blanket certificate. The definition includes companies which primarily distribute natural gas on a local basis.

IV. Effective Date

In order to make additional gas supplies available to the interstate market as quickly as possible, the Commission finds that good cause exists to make this rule effective upon date of issuance of this order.

(Natural Gas Act, 15 U.S.C. 717, *et seq.;* Natural Gas Policy Act of 1978, 15 U.S.C. 3301, *et seq.;* Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.;* Administrative Procedure Act, 5 U.S.C. 500, *et seq.;* E.O. 12009 42 FR 46267).

In consideration of the foregoing, the Commission adds a new § 284.222 to Subpart G of Part 284, Subchapter I, Chapter I of Title 18, Code of Federal Regulations, as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,119]

45 F. R. 2023 (January 10, 1980)

18 CFR Part 290

[Docket No. RM79-6; Order No. 48-A]

Collection of Cost of Service Information Under Section 133 of the Public Utility Regulatory Policies Act of 1978; Order on Rehearing and Reconsideration of Order No. 48

Issued January 4, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Order denying in part and granting in part petition for reconsideration.

SUMMARY: The Commission is modifying §§ 290.103, 290.404 and 290.601 of its regulations implementing section 133 of the Public Utility Regulatory Policies Act of 1978. These regulations govern procedures for the collection and reporting of information associated with the cost of providing electric service. This action is being taken in response to five petitions for reconsideration received by the Commission.

EFFECTIVE DATE: February 4, 1980.

FOR FURTHER INFORMATION CONTACT: Daniel G. Lewis, Federal Energy Regulatory Commission, Office of Electric Power Regulation, 825 North Capitol St., N.E., Washington, D.C. 20426, (202) 376-9227.

Procedures governing the collection and reporting of information associated with the cost of providing electric service.

On September 28, 1979, the Federal Energy Regulatory Commission (Commission) issued Order No. 48, containing final regulations implementing section 133 of the Public Utility Regulatory Policies Act of 1978 (PURPA), (44 FR 58687, October 11, 1979). Five petitions for reconsideration and/or rehearing were received from Consumers Power Company, Public Service Company of Colorado, Arkansas Power and Light Company, Southern Company Services, Inc., and Commonwealth Edison Company. Four other parties submitted supplementary comments: Detroit Edison Company, Appalachian Power Company, *et al.,*[1] Missouri Power and Light Company, and Virginia Electric and Power Company.

Section 290.104 *Costs of compliance.* Both Consumers Power and Detroit Edison argued that costs incurred in complying with Part 290 should be included in wholesale cost-of-service.

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[1] Appalachian Power Company, Boston Edison Company, Commonwealth Edison Company, Consolidated Edison Company of New York, Inc., Florida Power and Light Company, Indiana and

The petitions raise no new arguments, and the Commission will retain § 290.104 for the reasons stated in Order 48. These petitions have been denied by operation of law.

Section 290.404 *Customer groups to be reported.* Detroit Edison commented that clarification is needed concerning the rate groups and end-use categories to be reported and suggested improvements to the rule. Commonwealth Edison requested that the end use classes involving commercial office buildings be either deleted or better defined.

We decline to delete the end-use categories for commercial office buildings. In determining the end-use categories for which best estimates should be reported, the Commission attempted first to identify which customer groups within the general commercial and industrial class represent different consumption patterns within that class. Several groups were considered, including shopping centers, commercial office buildings, and other commercial uses. As a first step in carrying out the statutory requirements of section 133, the Commission selected commercial office buildings for reporting because the load for such customers is presumed to have a distinct effect on a utility's load pattern and tends to be coincident with many utilities' daily peaks. We acknowledge that many utilities will find it necessary to make a new analysis of commercial customers, possibly including surveys, to develop the information needed to comply with the regulations.

We regard the request for further definition of these end-use categories and the other comments as requests for interpretation of the regulations and agree that certain clarifications and interpretations are needed. We believe that the request for further definition of the term "commercial office building" is more appropriately handled through interpretations rather than a modification of the regulations because it is unlikely that a single definition can be constructed and applied to all utilities. We prefer to work with utilities on an individual or regional basis in order to define this category on a system-specific or regional basis. It is our intention to provide a procedure for interpreting Part 290 in response to specific requests. The Commission intends to provide additional definition for the commercial office buildings category within the context of this procedure.

Missouri Power and Light commented that it has a program of load research ordered by the Missouri Public Service Commission prior to the enactment of PURPA, that this program will not provide compliance with Part 290, and that it cannot use its present metering equipment to comply with Part 290 by the time of the 1982 filing. It suggested alternate wording to allow use of its best estimates in 1982 as well as in 1980. Appalachian Power Company, *et al.* Suggested other changes in § 290.404 based on overall difficulty in obtaining metered data for the 1982 filing.

We believe these utilities should deal with these situations by using the exemption or extension provisions in the regulations or, to the extent that there is uncertainty as to our requirements, by requesting interpretation of those regulations.

Section 290.404(g) *Reporting requirements.* Appalachian Power Company, *et al.* commented that the provisions of subparagraph (5) of § 290.404(g) are "ill-founded" and should be stricken. It suggests, after argument, that "the rules should simply require a description of how the estimate was derived, together with any available information on the accuracy of any borrowed or interpolated data which may have been used in preparing the estimate."

We do not agree that the provisions are "ill-founded." Having limited its

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Michigan Electric Company, Kentucky Power Company, Kingsport Power Company, Michigan Power Company, Ohio Power Company, Union Electric Company, and Wheeling Electric Company.

reporting requirements in certain cases to "best estimates," the Commission feels it must define, at least qualitatively, the utility's responsibility to make such estimates as accurate as is reasonable. However, upon reconsideration, we find that the wording of § 290.404(g)(5) may be unduly severe in its explicit requirement for successive improvement in the estimates. We have revised the wording of subparagraph (5) so that utilities will be required to demonstrate an effort to improve the level of accuracy relative to previous estimates, and to include in their filings a description of the method used for developing those best estimates reported.

Arkansas Power and Light, Southern Company Services, and Appalachian Power Company, *et al.* argued that the provisions of subparagraph (6) of § 290.404(g) (the estoppel clause) are unnecessarily punitive, tend to dictate procedural requirements for State regulatory agency proceedings, and are unlawful. A late filing by Virginia Electric and Power Company supported Southern Company Services' petition.

We agree with the petitioners' argument that such a clause would constitute a Federal determination of State regulatory agencies' permissible evidence rules. It would also prohibit introducing improvements in the data that might have been made subsequent to a filing with the Commission and prior to the rate case. We will, therefore, eliminate the estoppel clause in § 290.404(g)(6). Instead, the regulations will require utilities to provide best estimates of load data of sufficient quality and reliability on which to base rates. A utility unable to meet this standard will be required to explain why the estimates do not meet the standard and to indicate what steps it intends to take to achieve this standard for the next reporting period. Since there is no guarantee that a utility, by its second best estimate filing, will be reporting best estimates of a quality sufficient to permit their being used as a basis for rates, the new approach in paragraph (g)(6) requires the utility give notice in the prior filing of what it intends to do to correct this deficiency so that potential users of the information can determine whether such corrective measures are sufficient to achieve the standards in the next filing.

Section 290.601 *Exemptions.* Appalachian Power Company, *et al.* suggested that the provisions of paragraph (d)(1)(iii) of § 290.601, which permits newspaper publication of a summary of an exemption application in lieu of publication of the entire application, should be extended to paragraph (d)(1)(ii) which currently requires publication of the entire application in any official State publication. An additional comment suggested that paragraph (d)(2) be modified to require that comments on applications for exemption be served on the utility applicant.

These are useful comments. We have revised the wording of the referenced sections to include the changes suggested. The Commission has made two other modifications on its own motion. Paragraph (a)(5) has been added to § 290.601 requiring that each application for exemption include a notice suitable for publication in the Federal Register, which will properly identify the utility, the nature of the exemption sought, and a summary of the utility's basis for the application. Paragraph (d)(2) of § 290.601 has also been amended to define the period for filing comments on such application by reference to the single date most readily accessible to all interested persons and the Commission, *i.e.* the date the notice is published in the Federal Register.

Section 290.603 *Petitions for withdrawals of exemptions and extensions.* Public Service Company of Colorado stated its concern "that the approval of a party's application for a withdrawal of an extension for a small rate class might put undue pressure on (the utility) to conduct load research that might be of questionable value for the purposes of rate design, or for that matter, for the purposes of the party's intervention." The comment also alleged that certain timing problems may arise if exemptions or extensions are withdrawn. The Commission advises that in considering petitions under this section it will certainly take account of the impact of a withdrawal on the utility as well as the benefits that may or may not result from a withdrawal. Further, the utility will have an opportunity to comment on each petition affecting it. Therefore, we see no reason to change the section.

The Commission is making one other minor modification to Part 290 on its own motion.

Section 290.103(c) *Alternative reporting period.* The Commission is making a technical change in paragraph (c) of § 290.103 to insure that a utility will be able to use the previous fiscal year as an alternative reporting period.

The Commission Orders: (A) To the extent not granted above, the petitions for reconsideration of Order No. 48 are denied.

(B) Sections 290.103, 290.404 and 290.601 of the Commission's final regulations are amended as set forth above, effective February 4, 1980.

(Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2001–2645; Energy Supply and Environmental Coordination Act, 15 U.S.C. 791–798; Federal Power Act, as amended, 16 U.S.C. 792–828C; Department of Energy Organization Act, 42 U.S.C. 7101–7352, E.O. 12009, 42 FR 46267.)

In consideration of the foregoing, Part 290 of Chapter I, Title 18, Code of Federal Regulations is amended as set forth below, effective February 4, 1980.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,120]

45 F. R. 3568 (January 18, 1980); 45 F. R. 9729 (February 13, 1980)

18 CFR Part 46

[Docket No. RM80-9; Order No. 67]

Order Issuing Part 46 of the Commission's Regulations as Final Regulations; Public Utility Filing Requirement Under Section 211 of the Public Utility Regulatory Policies Act of 1978

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final regulations.

SUMMARY: This rule implements, in part, section 211 of the Public Utility Regulatory Policies Act of 1978 (PURPA) which amended section 305 of the Federal Power Act (the Act) by adding a new subsection (c). Subsection (c) imposes a reporting requirement upon any person holding certain interlocking positions between a public utility and any of a number of other entities and, additionally, imposes upon each public utility a requirement that it make public by January 31 of each year a list of its largest purchasers, based upon kilowatt hours consumed. This rule implements the latter requirement imposed upon the public utilities.

EFFECTIVE DATE: January 11, 1980.

FOR FURTHER INFORMATION CONTACT: Colette K. Bohatch, Federal Energy Regulatory Commission, Office of the General Counsel, Room 8113, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8079.

In the matter of Public Utility Filing Requirement Under Section 211 of the Public Utility Regulatory Policies Act of 1978.

Issued January 11, 1980.

This rule implements, in part, section 211 of the Public Utility Regulatory Policies Act of 1978 (PURPA) which amended section 305 of the Federal Power Act (the Act) by adding a new subsection (c). Subsection (c) imposes a reporting requirement upon any person holding certain interlocking positions between a public utility and any of a number of other entities and, additionally, imposes upon each public utility a requirement that each publish by January 31 of each year a list of its largest purchasers as defined therein, based upon kilowatt hours consumed. This rule implements the latter requirement imposed upon public utilities.

I. Background

On November 14, 1979, the Commission issued a Notice of Proposed Rulemaking issued in this docket, 44 FR 66205, *et seq*. In that notice, the Federal Energy Regulatory Commission (Commission) proposed regulations which would implement all aspects of section 305(c) of the Act.

In order to provide the public utilities sufficient time to compile and to file the lists by January 31, 1980, the Commission decided to issue the pertinent sections of the proposed rule as phase I of the final rule prior to addressing all of the provisions of the proposed rule in this docket in final form. The public comments which were directed to the compilation and filing of lists of the largest users were reviewed and changes were made to both § 46.2 and § 46.6 of the proposed rule in accordance with many of the suggestions. The other provisions of the proposed rule will be finalized in the near future.

II. Specific Issues

(A) Definitions

Many of the commenters expressed concern that the Commission reconcile the differences which exist between the proposed rule in this docket and the regulations implementing section 305(b). Section 305(c) differs from section 305(b) in several ways: one significant distinction involves the definition of "public utility". Section 305(b) is silent while section 305(c) defines public utility to include "any company which is part of a holding company system which includes a registered holding company unless no company in such system is an electric utility." The Commission decided to maintain the definition of "public utility" as found in § 46.2 of the proposed rule with necessary modifications to clarify this definition as used in section 305(c). The definition of "public utility", in § 46.2 of the final rule, conforms the rule to the definition in section 305(c) of the statute.

Comments were received which suggested excluding Federal, State, and local governmental agencies from the coverage of these reporting requirements on the basis that these agencies are not intended to be covered and it serves no useful regulatory purpose to do so. In response to these suggestions, the Commission has added a definition of "purchasers" which has the effect of excluding governmental agencies from this category.

(B) Public Utility Filing Requirement

Section 305(c) imposes upon public utilities a requirement that each utility publish by January 31st of each calendar year (commencing in 1980) a list of the purchasers who purchased the twenty largest annual amounts of electric energy measured in kilowatt hours in each of the preceding three calendar years.

The proposed rule would have required each public utility to report not only the name and business address but also the kilowatt hour consumption of each of these purchasers. Under § 46.3 of the final rule, each public utility shall provide only the name and address of each purchaser without publicly identifying the total kilowatt hours of electric energy purchased by each purchaser. Public disclosure of the actual kilowatt hour consumption is not required by the statute nor can the Commission find any compelling reason to so require. Commenters indicated a concern regarding the possible proprietary nature of such information in some cases.

Section 46.3 further specifies how a public utility should determine which of its purchasers should be listed. The twenty largest purchasers in each year should be identified on the basis of records maintained with the public utility except where one purchaser maintains more than one account, the utility should aggregate those accounts to arrive at the total kilowatt hours purchased by such purchaser.

The Commission is aware that total sales data may not be available by the January 31st filing date and accordingly has modified this requirement to provide a procedure, in § 46.3(e) of the final rule, for revising the list. The possibility does exist that a utility may have to rely upon estimates in order to compile this list. Each utility relying on estimates shall file no later than March 1 a revision of its largest purchaser list. Any utility filing a revised list will notify the newly listed purchasers as well as purchasers whose names were removed from the list.

III. Effective Date

Proposed regulations of Part 46 were originally issued for comment on November 14, 1979, and published in the Federal Register on November 19, 1979. 44 FR 66205, *et seq.* (Nov. 19, 1979). In order to provide public utilities sufficient time to comply with certain provisions of Part 46 by January 31, 1980, it is necessary for the Commission to issue a final rule implementing three definitions as set forth in § 46.2 and the public utility reporting requirement set forth in § 46.3. In light of the January 31st reporting requirement, good cause exists to issue this final rule effective immediately.

(Federal Power Act, as amended, 16 U.S.C. §§ 792–828c; Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §§ 2601–2645; Department of Energy Organization Act, 42 U.S.C. §§ 7101–7352)

In consideration of the foregoing, the Commission adds Part 46 to Subchapter B, Chapter I, Title 18 of the Code of Federal Regulations, as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,121]

45 F. R. 3888 (January 21, 1980)

18 CFR Parts 35 and 154
[Docket No. RM77-22]

Rate of Interest on Amounts Held Subject To Refund; Order Clarifying Orders Nos. 47 and 47-A

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Order Clarifying Order Nos. 47 and 47-A.

SUMMARY: This Order contains corrections to Order No. 47 (RM77-22, 44 FR 53538, September 14, 1979) and Order No. 47-A (RM77-22, 44 FR 65740, November 15, 1979). Calculations of the applicable average prime rate are to be based on the prime rate values published in the *Federal Reserve Bulletin*, or in the Federal Reserve's "Selected Interest Rates" (Statistical Release G. 13), for the fourth, third, and second months preceding the first month of each calendar quarter. The rates of interest prescribed by Order No. 47 (Docket No. RM77-22, 44 FR 65740, November 15, 1979) will not apply where a different rate of interest has been established by court order or by a Commission order, which was final and non-appealable on or before September 10, 1979, approving a settlement agreement.

EFFECTIVE DATE: October 1, 1979.

FOR FURTHER INFORMATION CONTACT: Clarence C. Burris, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8106-A, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357-8161.

December 26, 1979.

On September 10, 1979, the Federal Energy Regulatory Commission issued Order No. 47 in the above-referenced docket which established (1) a new, self-adjusting compounded interest rate on refunds, (2) a new, self-adjusting compounded carrying charge rate on deferred purchased gas costs, and (3) a reduction in the number of required refund reports, all to become effective October 1, 1979. By Order No. 47-A, issued November 8, 1979, the Commission denied rehearing of Order No. 47, and clarified the Commission's position that compounding is intended to apply after October 1, 1979, to all interest, regardless of when it accumulated.

Motions for reconsideration and clarification of Order Nos. 47 and 47–A were filed by Cities Service Gas Company (Cities Service) and Tennessee Gas Pipeline Company, Midwestern Gas Transmission Company, and East Tennessee Natural Gas Company (Companies), on November 27, 1979.

Companies noted a mechanical problem concerning operation of the Commission's new refund interest regulations. The Commission's interest rates for a given calendar quarter now reflect the arithmetic mean of the prime rate values for the second, third, and fourth months preceding the quarter, which values are published in the monthly *Federal Reserve Bulletin (FRB)*.[1] Companies state that it is not possible to calculate the applicable interest rate for a quarter at the very beginning of that quarter, however, because the monthly issue of the *FRB* necessary to perform the calculation is not available until sometime in the middle of the first month of the quarter. Specifically, they state that it is the prime rate value for the second month preceding a calendar quarter that will not be known until the *FRB* becomes available. Therefore, Companies suggest that we revise our regulations to provide that interest calculations reflect the prime rate values for the third, fourth, and fifth months preceding the calendar quarter.

It is true that the prime rate value for November, for instance, will not generally be available from the December *FRB* until sometime in mid-January.[2] That November value is nevertheless available from the Federal Reserve shortly after the end of November, albeit from sources less well-known than the *FRB*. For example, a monthly Federal Reserve statistical release entitled "Selected Interest Rates" (Statistical Release G.13) includes the prime rate value for the immediately preceding month, and is available within ten days after the end of the month. Thus, the prime rate value for November will be available in December's Statistical Release G.13 by December 10, in sufficient time to permit calculation of the applicable interest rate beginning January 1, the start of the next calendar quarter.

In light of the foregoing discussion, it is not necessary to revise our refund regulations so as to require refund interest rates to reflect the prime rate values for the third, fourth, and fifth months preceding the calendar quarter, as suggested by Companies. The currentness inherent in the refund regulations as presently structured may be preserved simply by reference to another source for prime rate information. However, in order to eliminate any uncertainty that the present regulations may have caused, and keep the refund interest rate as current as possible, we will amend the regulations to reflect Statistical Release G.13 as an acceptable alternate source of prime rate information.

Some companies may, however, continue to have difficulty in obtaining the data necessary to make calculations so as to enable them to make refunds during the first few weeks of a calendar quarter. Under those limited circumstances, we will authorize the Director of the Office of Electric Power and the Director of the Office of Pipeline and Producer Regulation, as appropriate, to assist the company in obtaining the necessary data upon reasonable request.

Cities Service and Companies also request the Commission to state clearly that, consistent with prior Commission practice, the rates of interest prescribed by Order No. 47 will not apply where a different stipulated rate of interest has been established by court order or by Commission order approving a settlement agreement. This policy is in line with that followed both by this Commission and its predecessor, the Federal Power Commission. *Cities Service Gas Company,* Docket No. RP74-4, Opinion No. 24-A, issued October 31, 1978; *Tennessee Gas Pipeline Company,* Docket Nos. RP71-16, RP71-57, and RP72-1, order issued April 15, 1977; *Northern Natural Gas Company,* Docket No. RP74-80, order issued November 5, 1976; *Columbia Gas Transmission Corp., et al.,* Docket No. RP74-81, *et al.,* order issued November 5, 1976. The following language from Order No. 513-A, which established the refund interest rates that preceded those now effective, is equally applicable here:

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[1] These values are generally found at page A–26, Table 1–34 in the *FRB*.

[2] In view of this recognition, we would change preamble statements about data availability which appear in Order No. 47 (Page 19 and Appendix A's Footnote ** at Page 36). Both references should now simply allude to the *FRB* that is published during the first month of a quarter.

> Where there is a final, non-appealable Commission order directing the disbursement of refunds of amounts collected or held during the time periods which are the subject of this order, the Commission does not intend to reconsider or modify those individual orders. The orders will stand as issued. However, where such orders have been issued but are not final and non-appealable on the date of this order, the natural gas company or public utility should, without further motion by the parties in the individual dockets, be required to comply with this order.

Thus, the rates of interest prescribed by Order No. 47 will not apply where a different stipulated rate of interest has been established by court order, or by a Commission order approving a settlement agreement which became final and non-appealable by September 10, 1979.

Order No. 47 made the revised interest rate rule effective as of October 1, 1979. These amendments merely clarify the intent of the regulations adopted in Order No. 47. Therefore, the amendments are hereby made effective as of October 1, 1979.

(Sec. 16, Natural Gas Act, 15 U.S.C. 717o; sec. 309, Federal Power Act, 16 U.S.C. 825h; Department of Energy Organization Act, Pub. L. 95-91; E.O. 12009, 42 FR 46267)

In consideration of the foregoing, Parts 35 and 154, of Chapter 1, Title 18, of the Code of Federal Regulations are amended as set forth below, effective October 1, 1979.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,122]

45 F. R. 3890 (January 21, 1980)

18 CFR Part 274

[Docket No. RM80-15; Order No. 65]

Final Regulations Implementing Filing Requirements of the Natural Gas Policy Act of 1978

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: On December 1, 1978, the Commission issued interim regulations to implement the provisions of the Natural Gas Policy Act of 1978 (NGPA) 44 FR 56448 *et seq.* Among those regulations was Subpart B of Part 274 which set forth filing requirements for applicants seeking well category determinations from jurisdictional agencies. On consideration of comments received since the issuance of December 1, 1978, and in light of subsequent amendments, the Commission is now amending Subpart B of Part 274. In addition, and except for those sections which deal with certain determinations for high cost natural gas priced under section 107 of the NGPA (§§ 274.205(b) through (d)), Subpart B is being issued as final regulations.

EFFECTIVE DATE: February 4, 1980.

FOR FURTHER INFORMATION CONTACT: Thomas P. Gross, Office of the General Counsel, Federal Energy Regulatory Commission, Room 4102-B, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357-8028, or Clarence Burris, Office of the General Counsel, Federal Energy Regulatory Commission, Room

8106–A, 825 North Capitol Street, NE, Washington, D.C. 20426, (202) 357–8161.

January 4, 1980.

I. Background

On December 1, 1978, the Federal Energy Regulatory Commission (Commission) issued interim regulations implementing the Natural Gas Policy Act of 1978 (NGPA) (43 FR 56448). Part 274, Subpart B of the interim regulations set forth the minimum filing requirements for applications to jurisdictional agencies for determinations of eligibility for various categories of natural gas. These categories are new natural gas and certain Outer Continental Shelf (OCS) gas (as defined in section 102 of the NGPA), natural gas from new onshore production wells (section 103), high-cost natural gas (section 107), and stripper well naturel gas (section 108).

Comments were invited from interested parties on or before February 1, 1979. Timely comments were received from a number of parties representing gas producers, gas and oil pipelines, distributors of gas (including municipalities and cooperatives), oil shippers, and public interest groups. The Commission has taken into consideration these questions and comments in developing this final regulation.

Since its original issuance on December 1, 1978, Part 271 has been amended by Order No. 42 (Docket No. RM79–68, 44 FR 48180, August 17, 1979), Order No. 42–A (Docket No. RM79–68, 44 FR 69642, December 4, 1979), Order No. 43 (Docket No. RM79–72, 44 FR 49651, August 24, 1979), Order No. 43–A (Docket No. RM79–72, 44 FR 67108, Nov. 23, 1979), Order No. 44 (Docket No. RM79–73, 44 FR 49656, August 24, 1979) and Order No. 44–A (Docket No. RM79–73, 44 FR 66783, November 11, 1979). The present order reflects these prior amendments.

II. Summary of Comments and Revisions to Part 274, Subpart B

Section 274.201 sets forth general requirements for filing applications for determinations of eligibility with jurisdictional agencies. Among other things, §§ 274.201(b) and 274.201(c) specify who may file an application for determination and who is required to sign the application. The Commission believes that any person designated by the jurisdictional agency as eligible to make filings under this subpart may also be the person who signs the application. Accordingly, § 274.201 is being amended by deleting paragraph (c) and amending § 274.201(b) to allow the person who is filing the application to sign the application.

Section 274.202 establishes filing requirements with jurisdictional agencies for applications for determinations for new natural gas (section 102). Among other things, this section requires the applicant to file an oath statement as to certain relevant facts, depending on whether the application for determination is for a new onshore well or a new onshore reservoir. Several comments stated that the oath requirements were confusing and too stringent.

After reviewing these comments, the Commission believes that the oath and filing requirements of this section are necessary and should not be modified. Although this section requires several different oath statements, this is necessary to verify the different facts associated with different categories of natural gas. One change has been made in § 274.202. Since several of the oath statements which accompany applications for determination of new onshore wells and new onshore reservoirs are the same, these statements have been consolidated into a new paragraph (e) in § 274.202. However, these statements are still required to be filed with the application.

Several comments suggested that the filing requirements in §§ 274.202 and 274.203 (new natural gas and certain OCS gas) and § 274.204 (new onshore production wells) be shortened, or that Form 121 be modified to expressly list the information required to be filed. These suggestions are not being adopted. Sections 102 and 103 of the

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NGPA impose certain statutory conditions which must be satisfied before a well qualifies for these categories. Sections 274.202 through 274.204 implement these sections of the NGPA by requiring that certain minimum information needed to make these determinations be submitted to the jurisdictional agency. In view of the stringent requirements imposed by the NGPA which must be met before a well qualifies under section 102 or 103, the Commission believes that the information required to be filed is necessary to satisfy the statutory mandate of the NGPA.

Furthermore, the Commission has considered revising Form 121 to list the filing requirements for each different category of gas and believes such revisions are unnecessary. The substantive information which must be filed with the jurisdicational agency is specifically listed in Part 274, Subpart B. Form 121 is intended to provide only general information concerning the application for determination of eligibility. This permits jurisdictional agencies to prescribe the specific format in which the information specified in Subpart B is to be submitted to the jurisdictional agency. The Commission is of the opinion that the flexibility of this approach will allow jurisdictional agencies to prescribe a format most useful for their purposes.

Section 274.202(c)(1)(iv) requires the applicant to submit a location plat which identifies the well for which the determination is sought and any other well which is producing, or produced after January 1, 1970, natural gas and which is within a 2.5 mile radius from the well for which a determination is sought. Since only wells which produced natural gas between January 1, 1970, and April 20, 1977, are relevant, § 274.202(c)(1)(iv) has been amended to require that only wells which produced natural gas during that period be identified on the location plat. A similar change is being made in § 274.202(c)(2)(iii).

Section 274.202(c)(2)(iii) (1,000 feet deeper test) requires applicants to file a location plat which includes specific identification of all marker wells within a 2.5 mile radius drawn from the well for which a determination is sought. One comment suggested that the applicant should not be required to identify marker wells if it can be shown that the completion locations for all wells within 2.5 miles are at least 1,000 feet shallower than the completion location for the subject well. This suggestion will not be adopted. If the applicant is claiming that the completion location of a new onshore well is 1,000 feet deeper than that for any marker well within a 2.5 mile radius, the record should illustrate those marker wells.

One comment suggested that marker wells which were not drilled to a depth sufficient to penetrate the reservoir into which the subject well is drilled should not be identified under the filing requirements of § 274.202. The comment misconstrues the significance of marker wells and the 1,000 feet deeper test. If the applicant is seeking a new onshore well determination pursuant to the 1,000 feet deeper test, then the applicant must show that the completion location of the new well is at least 1,000 feet deeper than the deepest completion location of each marker well within a 2.5 mile radius. Whether the marker well penetrates the reservoir into which the subject well is drilled is irrelevant. Accordingly, a marker well within the 2.5 mile radius which does not penetrate the reservoir in which the new well is completed but which is within 1,000 vertical feet of such completion location would still disqualify the new well as a new onshore well under section 102.

Section 274.202(d) establishes filing requirements for applications for determinations regarding new onshore reservoirs. One comment suggested an amendment to this section which would allow any subsequent application for determination of eligibility for wells in the same reservoir to refer to the previous application, thereby avoiding unnecessary, repetitious filings of the same information.

The Commission recognizes that unnecessary duplication of reports should be avoided. Accordingly,

§§ 274.202(d)(1)(B) and 274.203(c)(2) are being added to allow an applicant to make reference to a previously filed application for determination of eligibility which contains the same information required to be filed in his current application. The applicant may refer to applications previously filed by either himself or any other applicant. However, such previously filed applications must have been filed with the jurisdictional agency with which the current application is filed. Reference may be made only to those applications upon which the jurisdictional agency has made a determination of eligibility and which are on file with the Commission. This restriction is necessary to insure that the information to which the applicant refers is available to the Commission and the jurisdictional agency during the review period. The applicant should refer to the previously filed application by the jurisdictional agency docket number, the FERC docket or control number and the API well number.

Although the Commission expects this change to eliminate the filing of repetitious information, it should be noted that any information not contained in the previously filed application must be submitted with the current application and that each individual application must meet the substantial evidence test.

Section 274.202(d)(1)(v) requires the applicant to state under oath that he has made or caused to be made a diligent search of all records, including production, State severance tax, and royalty payment records, which are reasonably available and relevant to the determination of eligibility. Several comments suggested that applicants should not be required to search royalty payment and State severance tax records because they do not contain information material to the determination of eligibility. It was further suggested that if such a search is required, it should be limited to such records only where applicable.

The Commission believes that a search of these records is necessary because the records may contain evidence relevant to determining whether natural gas was produced in commercial quantities. However, the regulation states, and the Commission intends, that the search may be limited to records which contain information relevant to the determination of eligibility.

Sections 274.202(d)(2)(ii) (A) through (D) require the applicant to answer certain questions under oath concerning the production of natural gas in commercial quantities, and the existence of suitable facilities for the production and delivery of natural gas to a pipeline. This section was amended in Order No. 42-A (Docket No. RM79-68, 44 FR 69642, December 4, 1979). The information is designed to determine whether the natural gas from the new onshore reservoir is subject to the behind-the-pipe exclusion or the withheld gas exclusion of sections 102(c)(1)(C) (ii) or (iii) of the NGPA, respectively. This order retains the above mentioned tests issued in Order No. 42-A, but renumbers the sections so that the behind-the-pipe test is contained in § 274.202(d)(2)(ii) and the withheld-gas exclusion is contained in § 274.202(d)(2)(iii). Section 274.202(d)(2)(ii)(D) has been eliminated since the above tests will determine whether the gas qualifies as new natural gas.

Section 274.203 established the filing requirements for new reservoirs on old OCS leases. Section 274.203(e) (1) through (4), now § 274.203(e)(1) (i) through (iii) and § 274.203(e)(2), established additional filing requirements for new reservoirs on old OCS leases if the reservoir was penetrated prior to July 27, 1976. In particular, §§ 274.203(e) (1) through (3) (now renumbered as §§ 274.203(e)(1) (i) through (iii)) require the applicant to submit the results of certain production tests and evidence which demonstrate as of the time of such tests or as of the time such evidence was obtained, that the reservoir was not capable of producing in paying or commercial

quantities. Several comments stated that the filing requirements of this section changed the burden of proof in section 102(d)(4) of the NGPA with respect to the tests set forth in section 102(d)(2)(2)(B) (i) through (iii).

The Commission believes that if any of the tests or evidence set forth in section 102(d)(2)(B) (i) through (iii) of the NGPA were performed on or before July 27, 1976, the results of such tests or evidence should be submitted by the applicant. However, if no such tests were performed and no other evidence concerning the reservoir's capability to produce in paying quantities exists on or before July 27, 1976, then the applicant should submit an oath statement to that effect. Accordingly, and in response to the above comments, §§ 274.203(e)(1) (i) through (iii) are changed to require the applicant to submit the test results and evidence listed in §§ 274.203(e)(1) (i) through (iii), to the extent such tests were performed on or before July 27, 1976. If such data is not available because such tests were not performed and no other evidence showing the well was capable of producing in paying quantities was in existence on or before July 27, 1976, the applicant must submit an oath statement to such effect.

One comment stated that this oath statement had no statutory basis. The Commission believes that this statement is necessary in order to insure that none of the tests which would have generated the information listed in §§ 274.203(e)(1) (i) through (iii) have been performed. Since the applicant has the burden of showing that the reservoir is a new reservoir on an old OCS lease, he must submit such a statement in order to meet this burden.

Another comment requested that the filing requirements in §§ 274.202, 274.204 and 274.205 be expanded to include certain additional information which would be helpful to the jurisdictional agency in making determinations of eligibility. The Commission declines to expand the filing requirements in these sections beyond that which is necessary for jurisdictional agencies to make a determination of eligibility. If jurisdictional agencies desire additional information for purposes of making such determinations, § 274.201(c) permits the jurisdictional agency to require the additional information if it deems appropriate.

Section 274.204 establishes the filing requirements for applications for determination of eligibility for new onshore production wells. One comment stated that the filing of a completion report as required by § 274.204(b) is unnecessary because, in some states, the drilling permit already contains the information needed for this determination.

The Commission notes that this report contains, among other things, the date on which surface drilling began, and it is needed to establish whether drilling began on or after February 19, 1977. Therefore, the Commission believes that all applicants should file this report. However, if jurisdictional agencies find that the filing of this report is unnecessary and that another reliable document providing the same information is available, they may submit an application for alternative filing and notice requirements under § 274.207. The Commission notes, however, that it is desirable to establish uniform filing requirements for all jurisdictional agencies. Accordingly, requests for alternative filing and notice requirements will be reviewed with care and granted only where circumstances warrant a change.

In applying for a determination for a new onshore production well, the applicant is required by § 274.204(c) to submit a location plat which identifies the well for which a determination is sought and all other wells within the state law proration unit (as defined in § 271.305(a)(2)) in which the well for which a determination is sought is located. This section is being amended to require the applicant to also identify the state law proration unit.

Section 274.205 sets forth the filing requirements for high-cost natural gas. Included in this section are the revisions made in Docket No. RM79-44 (44 FR 61950, October 27, 1979). Section 274.205

paragraphs (b), (c) and (d) will remain as interim rules until there is further action by the Commission.

Section 274.206 establishes the filing requirements for applicants seeking to establish stripper well status. Order No. 44 (Docket No. RM79-73, 44 FR 49656, August 24, 1979) amended § 274.206 by requiring the applicant to submit certain records and test results if the maximum efficient rate of flow for the well had not previously been established. The present order further amends this section by adding subparagraph (a)(3) to require the applicant to submit a copy of the results of any tests which establish a maximum efficient rate of flow.

Sections 274.206(a)(2), 274.206(a)(4)(i), 274.206(b)(3), and 274.206(d)(3) require the applicant to submit production records, tax records, or verified billing statements upon which the average production for the 90-day production period is based. The Commission believes that, in many cases, the filing of the actual records or billing statements is unnecessary and that a summary of such records or billing statements will serve the same purpose. These sections are therefore being amended to allow the applicant to submit a summary of the contents of such records or billing statements in lieu of the actual documents, but only if permitted by the jurisdictional agency's filing requirements.

Order No. 44 clarified § 271.804(a) of the interim regulations concerning the methodology for determining the rate of production from a well for which a stripper well determination is sought. Section 271.804(a) requires an applicant to determine a well's rate of production by using the total volume of natural gas produced from the well regardless of whether the well is completed in more than one interval. In order to emphasize that production from a stripper well is based on the total volume from the well and not the production from each interval, § 274.206(a)(9) has been added to the filing requirements to require the applicant to submit production records for each completion location penetrated by the well bore.

Section 274.206(a)(7) (now renumbered as § 274.206(a)(8)) requires the applicant to submit production records for crude oil produced from the well for the 90-day production period on which the application is based. In those cases where no crude oil was produced from the well, the regulation is being amended to require an oath statement to that effect.

Section 274.206(a)(8) requires the producer to file "an inventory of the lease and production equipment." Several comments suggested that this filing should not be required until the producer submits a request for continued stripper well classification following the use of enhanced recovery techniques. It was further suggested that the Commission define the inventory of equipment essential for the filing.

The Commission agrees that the filing of this information is more relevant if the applicant claims an increase in production due to the use of enhanced recovery techniques. Accordingly, this filing requirement is being deleted from § 274.206(a). Section 274.206(c), pertaining to enhanced recovery techniques, is being amended to require the applicant to file a description of all processes and equipment which constitute enhanced recovery techniques. The applicant is also required to submit a list of the lease and production equipment used prior to the installation of the enhanced recovery techniques. The Commission intends such lists to include equipment which directly affects the production of natural gas, such as compression facilities, pumps, chokes, and intermittors, rather than a detailed inventory of all equipment used at the wellhead. The Commission anticipates that this information will provide a basis for the jurisdictional agency to determine whether increased production from the well has resulted from the implementation of recognized enhanced recovery techniques.

The Commission amended § 271.803(a) in Order No. 44 to specify that normal completion operations performed within two years of the initial completion do not qualify as recognized enhanced recovery techniques. In view of this, § 274.206(c) is now amended to require the well completion report to be filed when an applicant seeks a determination that increased production resulted from use of recognized enhanced recovery techniques.

Other comments were submitted regarding "production days" and certain other requirements which must be satisfied to qualify for stripper well status. These requirements are discussed in Order No. 44, and in Order No. 44–A (Docket No. RM79–73). Producers should refer to these orders for further explanation of these issues.

Section 274.207 permits jurisdictional agencies to submit an application to the Commission to establish alternative filing and notice requirements. One comment suggested that this section be amended to allow for a special filing procedure for small producers. The Commission believes that this suggestion should not be adopted. First, we note that the NGPA does not exempt small producers from applying for jurisdictional agency determinations for eligibility. The filing requirements imposed by this subpart are intended to provide the jurisdictional agency with the minimum information which is needed for the jurisdictional agency to make a reliable determination of a well's eligibility for certain categories and to provide the Commission with sufficient information to determine whether the jurisdictional agency's determination of eligibility meets the substantial evidence test of section 503 of the NGPA. This information is necessary regardless of a producer's production capability. Accordingly, no special filing procedure is being established for small producers. However, if a jurisdictional agency believes that small producers with natural gas wells within its jurisdictional region are capable of submitting the necessary information in some abbreviated fashion, it may submit an application to the Commission for such filing and notice requirements under § 274.207.

Another comment suggested that the oath statements in §§ 274.202 through 274.206 be amended to allow the applicant to file a one-time blanket affidavit with the Commission in lieu of the oath statement which must accompany each application. This suggestion is not being adopted. The Commission believes that the statement under oath is necessary for each application because it indicates that the applicant has carefully considered the application and all information contained therein.

The oath statements in §§ 274.202 through 274.206 require the applicant to state that he has no knowledge of any other information not described in the application which is inconsistent with his conclusion. One comment suggested that this be amended to require the applicant to submit all information relevant to the determination, not only information favorable to the applicant's conclusion.

The Commission believes that the regulations already require submission of all relevant information. The Commission intends this part of the oath statement to require the applicant to present not only all evidence which supports the applicant's conclusion, but also all relevant evidence which does not support his conclusion. The regulations require the applicant to submit a statement under oath that he has no knowledge of any other information not described in the application which is inconsistent with his conclusion. An important purpose of this oath statement is to insure that the applicant has searched and reported to the jurisdictional agency all information which is reasonably available and which does not support his conclusion.

Sections 274.202, 274.203, and 274.206 require the applicant to state under oath that he has searched or caused to be searched all records relevant to the determination of eligibility which are reasonably available. One comment questioned whether this search was limited to company records, state production records, or both. Other comments stated that the search should be limited to the producer's records since state records are usually not helpful and are not in good condition, or that the search should be limited to records which the producer believes might contain information relevant to the determination.

The Commission intends that all records, including company records and state records, should be searched for information which is reasonably related to the determination of eligibility. This search is needed to assure that the application for determination of eligibility is accurate and complete and that all information which is both favorable and unfavorable to the applicant is submitted to the jurisdictional agency and is available to the Commission upon review of the jurisdictional agency determination.

One comment was submitted which suggested that Form 121 be amended to provide the FERC rate schedule designation, if applicable. This suggestion will not be adopted. The rate schedule number has no bearing on a determination for eligibility. Form 121 contains the contract date which should assist interested persons in locating the rate schedule.

Form 121, item No. 6, requires the applicant to report the estimated annual production from the well for which a determination of eligibility is sought. One comment suggested eliminating this information. The Commission believes that this information should be reported because it assists purchasers and third parties in determining which applications should be protested.

III. Public Procedures and Effective Date

The regulations in Part 274 were originally proposed for comment in November of 1978 and issued as interim regulations on December 1, 1978 (43 FR 56448, December 1, 1978). For a period of sixty (60) days thereafter, the Commission received comments and held public hearings on the regulations. By this process the Commission complied with the provisions of section 502(b) of the NGPA. The amendments that appear in this final rule are based on the consideration given to the information received during the above described notice, comment, and hearing process.

Therefore, the provisions of this part shall be effective thirty (30) days after issuance.

(Natural Gas Policy Act of 1978, (15 U.S.C. 3301 *et seq.*,) Department of Energy Organization Act, (42 U.S.C. 7101 *et seq*); E.O. 12009, 42 FR 46267.)

In consideration of the foregoing, Subpart B of Part 274, Chapter I, of Title 18, Code of Federal Regulations, is amended as set forth below, effective 30 days from the date of issuance. These rules, as amended, are final regulations with the exception of paragraphs (b), (c) and (d) of § 274.205 which will remain as interim rules until further notice.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,123]

45 F. R. 3898 (January 21, 1980)

18 CFR Part 274

[Docket No. RM79-3; Order 66]

Determinations by Jurisdictional Agencies; New Mexico Application for Alternative Filing Requirements

Issued: January 4, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: This rule adds § 274.208(a) to the Federal Energy Regulatory Commission's regulations implementing the Natural Gas Policy Act of 1978. The new section provides alternative filing requirements for certain well determination applications to the New Mexico Oil Conservation Division.

EFFECTIVE DATE: January 4, 1980.

FOR FURTHER INFORMATION CONTACT: Mark Magnuson, Federal Energy Regulatory Commission, 825 North

Capitol Street NE., Washington, D.C. 20426, (202) 357-8511.

Order Issuing Alternative Filing Requirements

On September 18, 1979, the New Mexico Oil Conservation Division, Energy and Minerals Department (New Mexico) filed an application with the Federal Energy Regulatory Commission (Commission) for approval of alternative requirements pursuant to § 274.207 of the Commission's regulations. The proposed alternative filing requirements would apply to determinations that certain wells drilled in existing proration units in New Mexico are new, onshore production wells. Notice of the New Mexico application was issued on October 10, 1979.[1] The comment period expired on October 31, 1979, without any comments being submitted by the public.

Section 103 of the Natural Gas Policy Act of 1978 (NGPA) establishes ceiling prices for new, onshore production wells. Applicants seeking a section 103 determination of eligibility are required to file with the jurisdictional agency the information specified in § 274.204 of the Commission's interim regulations, unless the Commission has approved alternative filing requirements pursuant to § 274.207. In its application, New Mexico requests that the filing requirements of § 274.204(d), (e) and (f) be modified for applications seeking a section 103 determination for infill wells[2] drilled in accordance with New Mexico Order Nos. R-1670-T (regarding the Blanco Mazaverde pool) and R-1670-V (regarding the Basin-Dakota pool). New Mexico states that these two orders provide for the optional drilling of an additional well on each proration unit in the Blanco-Mesaverde and Basin-Dakota pools and constitute a finding by New Mexico that the proration units within these two pools cannot be effectively and efficiently drained by the existing wells.[3] Accordingly, New Mexico requests alternative filing requirements for applicants seeking section 103 determinations for infill wells within the subject pools because New Mexico has already made the explicit finding required by § 271.305 of the Commission's regulations that a second well in each existing proration unit in the subject pools is necessary to effectively and efficiently drain the portion of the reservoir covered by that proration unit.

The Commission concludes based upon the facts set forth in the New Mexico application that alternative filing requirements are appropriate for wells drilled in accordance with the above-identified orders. Therefore, Part 274, Subpart B is amended by adding § 274.208(a) to provide separate filing requirements for applications requesting section 103 determinations of infill wells in the Blanco-Mesaverde and Basin-

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[1] 44 FR 59603, October 16, 1979.

[2] An infill well is a well which, for geological reasons, is necessary to drain a portion of a reservoir which is not being effectively and efficiently drained by any existing wells in the reservoir.

[3] In Order No. R-1670-T, New Mexico found, inter alia:

(12) That the producing formation of the Blanco Mesaverde Pool is comprised of various overlapping, interconnecting, and lenticular sands of relatively low permeability, many of which are not being efficiently drained by existing wells in the pool but which could be more efficiently and economically drained and developed by the drilling of additional wells pursuant to the rule changes proposed by the applicant.

In Order No. R-1670-V, New Mexico found, inter alia:

(13) That the producing formation of the Basin-Dakota Gas Pool is comprised of various sands of low permeability and porosity which are not being efficiently and effectively drained by existing wells in the various proration units in the pool, and which can be more efficiently and effectively drained by the drilling of additional wells pursuant to the rule changes proposed by the applicant.

(14) That the infill drilling of a second well on an established proration unit in the Basin-Dakota Gas Pool is necessary to effectively and efficiently drain a portion of the reservoir covered by the proration unit which cannot be effectively and efficiently drained by any existing wells within the proration unit.

Dakota pools which are drilled in accordance with New Mexico Order Nos. R-1670-T and R-1670-V. In approving the New Mexico application, the Commission finds that an infill drilling program is necessary to effectively and efficiently drain the proration units in the Blanco-Mesaverde and Basin-Dakota pools in New Mexico and that the determinations made by New Mexico in this respect in Order Nos. R-1670-T and R-1670-V are supported by substantial evidence. This finding is based on Order Nos. R-1670-T and R-1670-V, and the data submitted with the New Mexico application.

The primary difference between the filing requirements of § 274.204 regarding new, onshore production wells, and the alternative plan set forth in the New Mexico application involves the requirements of § 274.204(f). Subsection (f) requires, in part, that the applicant, who is seeking a section 103 determination for a new well which is drilled into an existing proration unit, submit "appropriate geological evidence and engineering data [to demonstrate] that the new well is necessary to effectively and efficiently drain a portion of the reservoir covered by the proration unit which cannot be effectively and efficiently drained by any existing well within the proration unit." The New Mexico alternative plan proposes that the applicant satisfy the above requirement by merely specifying the appropriate New Mexico order authorizing an infill well drilling program. New Mexico asserts that the proposed alternative filing requirements will provide substantial evidence on which a determination of a new, onshore production well can by made. The New Mexico orders verify that the pertinent geological and engineering data showing the necessity for second wells in existing proration units within the subject pools has already been accumulated under oath at hearing before New Mexico.[4]

The Commission agrees that it is unnecessary for each applicant to present, on a well-by-well basis, the data required by subsection (f). Because New Mexico has already collected the pertinent geological and engineering data, issued effective and efficient drainage findings in Order Nos. R-1670-T and R-1670-V with regard to this data, and filed this data with the Commission, further documentation on a well-by-well basis by the applicant is unnecessary. Accordingly, the Commission concludes that an applicant requesting a section 103 determination for well(s) subject to those orders should reference the appropriate New Mexico order rather than submit geological and engineering data already on file with New Mexico and the Commission.

In view of the above discussion, the Commission further concludes that to eliminate unnecessary duplication, the requirement of § 271.305(b) that such data be included in the notice of determination is deemed satisfied as Order Nos. R-1670-T and R-1670-V constitute the explicit effective and efficient drainage finding required by § 271.305(b). The Commission also concludes the requirement of § 271.305(c) that the jurisdictional agency notify the Commission of its finding is deemed satisfied under the alternative plan approved by this order.

New Mexico also requested several other changes in the requirements of § 274.204. The New Mexico alternative plan proposes to modify the oath statement required by § 274.204(d) in three respects. First, the proposed plan would omit the statement required by § 274.204(d)(2) that "the well satisfies any applicable federal or state well spacing requirements." This portion of the oath statement tracks the language in section 103(c)(2) of the NGPA.[5]

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[4] Certified copies of records relied on by New Mexico in adopting its poolwide infill well orders were included with its application for alternative filing requirements.

[5] The NGPA defines a section 103 new, onshore production well, in part, as a new well "which satisfies applicable Federal or State well-spacing requirements, if any."

Because the controlling statute explicitly requires that wells must satisfy applicable well spacing requirements, the Commission believes that this oath statement is necessary and should be retained in the alternative filing requirements approved by today's order.

The New Mexico alternative plan also proposes to modify that portion of the oath statement contained in § 274.204(d)(3). Subsection (d)(3) requires the applicant to submit an oath statement that the subject well is *not* within a proration unit:

(i) Which was in existence at the time the surface drilling of the well began;

(ii) Which was applicable to the reservoir from which such natural gas is produced; and

(iii) Which applied to any other well which either produced natural gas in commercial quantities or the surface drilling of which was begun before February 19, 1977, and was thereafter capable of producing natural gas in commercial quantities.

The New Mexico plan proposes to require the applicant to submit an oath statement that the new well *is* (rather than is *not*) in a proration unit which satisfies the requirements of subsection (d)(3).

Under § 274.204(f) the applicant is not required to file the oath statement under § 274.204(d)(3) if the applicant is seeking a determination under the Commission's special rule in § 271.305 respecting a new well drilled in an existing proration unit. All wells for which applicants will seek section 103 determinations pursuant to this alternative plan will be subject to § 271.305 and § 274.204(f) as second wells within existing proration units covered by two New Mexico Orders Nos. R-1670-T and R-1670-V. These wells may qualify as new, onshore production wells *only* under the special rule of § 271.305. Since § 274.204(f) excuses applicants subject to the special rule of § 271.305 from submitting the oath statement required by § 274.204(d)(3), the Commission concludes that the oath statement proposed in the New Mexico alternative plan is neither necessary nor useful. Accordingly, this part of the oath statement is not included in the alternative filing requirements approved by this order.

Finally, the New Mexico alternative plan proposes to modify the oath statement required by § 274.204(d)(4). This section requires the applicant to state under oath that *"on the basis of the documents submitted in the application,* the applicant has concluded that to the best of his information, knowledge and belief, the natural gas for which he seeks a determination is produced from a new, onshore production well" (emphasis added). Under the alternative plan approved by this order, the applicant will not submit the record for Order Nos. R-1670-T and R-1670-V with the application. Accordingly, the oath statement required by § 274.204(d)(4) is modified for the purposes of the New Mexico alternative plan approved by this order to omit the requirement that the applicant's conclusion be based on "documents submitted in the application."

The New Mexico alternative plan also proposes to delete the requirement of § 274.204(e) that the applicant submit, "if the jurisdictional agency so requires, certified copies of records relied on by the applicant including copies of the agency's official files." Since the material required by § 274.204(e) must be submitted only "if the jurisdictional agency so requires," and since the Commission believes that the jurisdictional agency should be permitted to exercise its discretion in requiring certified copies, this provision is retained in the alternative plan approved by this order.

The alternative plan approved by this order also modifies the requirements of § 274.204(c) by requiring the applicant to locate and identify the subject proration unit.[8] Since the applicant must submit a location plat which locates and identifies the subject well and all other wells in the proration unit, the Commission believes it is appropriate that the location plat also locate and identify the subject proration unit.

Public Procedures and Effective Date

A notice regarding the New Mexico application was issued on October 10, 1979. The Commission stated that comments on the proposed plan would be accepted if received on or before October 31, 1979. No comments were received. In view of the above discussion, the Commission approves the New Mexico alternative plan set forth in its application with modifications noted above. The Commission believes that good cause exists to make the alternative plan effective immediately for all determinations which have not yet become final under § 275.202 as of the day before the date of issuance of this order.

(Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.;* Department of Energy Organization Act, 42 U.S.C. 7107, *et seq.;* Exec. Order No. 12009, 42 FR 46267; Natural Gas Policy Act of 1978, 15 U.S.C. 3301, *et seq.)*

In consideration of the foregoing, Part 274 of Subchapter H, Chapter I, title 18, Code of Federal Regulations is amended as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,124]

45 F. R. 5677 (January 24, 1980)

18 CFR Parts 201 and 282
[Docket No. RM79-14]

Regulations Implementing the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978

January 18, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Technical Amendments to Order No. 49-A.

SUMMARY: On December 27, 1979, the Federal Energy Regulatory Commission (Commission) issued Order No. 49-A, an order on rehearing in Docket No. RM 79-14 (44 FR 767, January 3, 1980). In order to implement fully the modifications to the accounting regulations as described in the preamble in Order No. 49-A, the Commission hereby adopts the technical amendments set forth below.

EFFECTIVE DATE: January 18, 1980.

FOR FURTHER INFORMATION CONTACT: Barbara K. Christin, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8113, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357-8079.

SUPPLEMENTARY INFORMATION:

I. Discussion

On December 27, 1979, the Federal Energy Regulatory Commission (Commission) issued an order on rehearing in Docket No. RM79-14, captioned as Order No. 49-A (45 FR 767, January 3, 1980). The order included, in part, certain amendments to the accounting provisions of the incremental pricing program regulations.

The amendments adopted to the accounting regulations were discussed in the preamble in Order No. 49-A in Section II.G, "Accounting Regulations" (pgs. 23-25 of the mimeo, 45 FR 772-73). In order to implement fully the modifications to the accounting regulations as described in the preamble, the Commission adopts the amendments set forth below (in addition to those adopted in Order No. 49-A).

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[8] Section 274.204(c) requires an applicant to submit "a location plat which locates and identifies the well for which a determination is sought and all other wells within the proration unit in which the well for which a determination is sought is located."

II. Effective Date

The Commission makes the regulations below effective immediately for the reason that they are technical in nature and, in addition, are accounting regulations, which the Commission views as analogous to rules of practice and procedure, and thus not subject to the notice requirement of section 553(d) of the Administrative Procedure Act.

(Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.;* Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, 15 U.S.C. 3301, *et seq.;* Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.*)

In consideration of the foregoing, the commission amends Parts 201 and 282 of Title 18, Code of Federal Regulations, as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,125]

45 F. R. 5678 (January 24, 1980)

18 CFR Parts 270 and 271

[Docket No. RM80-14; Order No. 68]

Rules Generally Applicable to Regulated Sales of Natural Gas and Ceiling Prices; Final Regulations

January 18, 1980.

AGENCY: Federal Energy Regulatory Commission, Department of Energy.

ACTION: Order issuing final rules.

SUMMARY: The Federal Energy Regulatory Commission gives notice that it is amending and issuing as final rules, the interim regulations in subparts E and F of Part 271 concerning first sales of natural gas subject to existing and successor intrastate contracts and intrastate rollover contracts under sections 105 and 106(b) of the Natural Gas Policy Act of 1978. The interim regulations in Part 270, concerning the definition of "successor to an existing intrastate contract" and resales are also amended and issued as final rules.

EFFECTIVE DATE: February 15, 1980.

FOR FURTHER INFORMATION CONTACT: Scott E. Koves, Federal Energy Regulatory Commission, Office of the General Counsel, 825 North Capital Street NE., Washington, DC 20426, (202) 357-8317.

I. Introduction

This order issues final regulations under sections 105 and 106(b) of the Natural Gas Policy Act of 1978 (NGPA). These regulations replace the interim regulations in Subparts E and F of Part 271 which implement sections 105 and 106(b) of the NGPA (December 1, 1978, 43 FR 56448). The order also amends final regulations in Part 270. The following is a description of interim regulations formerly contained in Subparts E and F:

A. *Subpart E—Existing Intrastate Contracts.* Subpart E of Part 271 of the interim rules sets forth the procedures for determining maximum lawful prices under section 105 of the NGPA. These prices cover gas sold under existing intrastate contracts and successors to existing intrastate contracts. The maximum lawful price of any section 105 gas depends on the "contract price" applicable on November 9, 1978. If the contract price that was paid (or would have been paid had deliveries occurred) on November 9, 1978, was equal to or less than $2.06, then, pursuant to section 105(b)(1), the maximum lawful price is the lower of the section 102 maximum lawful price or the "price under the terms of the existing contract" as those terms were in effect on November 9, 1978. As provided in § 270.205(b), fixed and indefinite price escalator terms in the existing contract on November 9, 1978, can operate to increase the price up to the new natural gas price. Section 105(b)(1) was implemented by § 271.502(a) of the interim regulations.

If the contract price that was paid (or would have been paid had deliveries occurred) on November 9, 1978, exceeded $2.06, then, pursuant to section 105(b)(2), the maximum lawful price is the higher of the section 102 maximum lawful price, or the contract price actually charged on November 9, 1978, escalated each month by the inflation adjustment factor applicable to such month. (*See* NGPA section 101(a)). Section 271.502(b) of the interim regulations implements section 105(b)(2) of the NGPA.

The regulations under Subpart E also refer to the applicable reporting obligations under Part 276 [1] (*see* § 271.503); provide an explanation of how the "contract price" is to be determined (*see* § 271.504); and contain a special rule generally prohibiting contract modifications that shift "production-related costs" to the purchaser or that provide for an earlier date of deliveries (*see* § 271.505).

B. *Subpart F—Intrastate Rollover Contracts.* Subpart F of Part 271 implements section 106(b) of the NGPA which establishes maximum lawful prices for first sales of natural gas under "intrastate rollover contracts." The term "rollover contract" is defined in section 2(12) of the NGPA and can generally be described as a contract, other than a "successor contract",[2] that replaces an "existing contract" which expired of its own terms on or after November 9, 1978.

Contract term extensions taking effect on or after November 9, 1978, are to be ignored for purposes of determining whether gas qualifies as section 105 or 106 gas.

Pursuant to section 106(b)(1) of the NGPA, the maximum lawful price for first sales under intrastate rollover contracts is set at the higher of the highest price actually paid under the expired contract in the month in which the rollover occurs, escalated by the inflation adjustment factor for each succeeding month, or $1.00 escalated by the inflation adjustment factor since April, 1977. Section 271.602(a) implements section 106(b)(1) of the NGPA.[3]

Like Subpart E, Subpart F also refers to the applicable filing requirements in Part 276 (*See* § 271.603), and contains a special rule dealing with contract modifications which shift production-related costs to the purchaser (*See* § 271.604).

II. Summary of Comments and Discussion.

A. *Prior Determinations—Sections 105 and 106(b).* Neither Subpart E nor Subpart F requires producers to seek a prior determination of eligibility. Several comments assert that section 501(c) of the NGPA places on the Commission a responsibility to make prior determinations of eligibility respecting sales subject to sections 105 and 106(b), and that the Commission has abrogated that responsibility.[4] Section 501(c), entitled "Delegation of Certain Determinations," gives the Commission the authority to delegate to a State agency any of its "functions" with respect to, *inter alia*, sections 105 and 106(b). The comments argue that, because we have made no such delegations, we are required to make determinations of eligibility under sections 105 and 106(b) ourselves.

We believe that the comments improperly construe the term "determination" in the title to section 501(c). Section 501 gives the Commission its general rulemaking authority under the NGPA and gives it the authority to delegate its rulemaking functions relating to sections 105, 106(b), and 109(a) (1) and (3) to State agencies. Such a delegation authority cannot be turned into a Congressional mandate to conduct a prior determination of eligibility to determine maximum lawful prices under section 105 or 106(b) for each of the thousands of sales made under existing intrastate contracts and intrastate rollover contracts. The NGPA and its legislative history are silent as to how section 105 or section 106(b) is to be administered by the Commission and do not specifically provide for or require prior determinations for section 105 or 106(b) gas. We had considered and rejected use of such a prior determination process in issuing interim regulations.[5] In our order issued December 1, 1978, in Docket No. RM79-3, [43 FR 56518] we stated:

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[1] Final Part 276 Regulations Under the Natural Gas Policy Act of 1978, Docket No. RM79–30, Order Amending Part 276, Issuing Part 276 as Final Regulations and Promulgating FERC Forms 122, 123, and 124 and Accompanying Affidavits and Instructions. (Issued March 23, 1979) (44 FR 18647)

[2] *See* NGPA section 2(14); § 270.101(b)(9).

[3] Section 271.602(b) implements section 106(b)(2) which establishes the maximum lawful price applicable to certain State or Indian production or royalty shares under rollover contracts at the new natural gas price under section 102 of the NGPA.

[4] These comments were also directed at section 106(b) of the NGPA. Our conclusions, *infra*, respecting the administrative infeasibility of such a prior determination process apply equally to that section of the NGPA. Accordingly we conclude that a prior determination is not required for section 106(b) either.

> Given the administrative burdens attendant on making such determinations, the delay which such a determination process would cause, and the efficacy of the current reporting system in providing the information necessary for auditing to ensure compliance with the pricing limitations in the statute, the Commission can foresee no valid reason for instituting such a determination procedure.

We affirm that finding today.

Requiring prior determinations for each of the tens-of-thousands of section 105 or 106(b) contracts would prove to be an administrative impossibility.

B. *Determination of "Contract Price" and "Price Under the Terms of the Existing Contract"—Section 105.* The term "contract price" in section 105 is used to determine whether a contract qualifies under paragraph (b)(1) or (b)(2) and to determine the maximum lawful price in paragraph (b)(2).

Several parties requested clarification of how "contract price" is to be determined under section 105, particularly with regard to severance taxes. Part of this confusion may be based on the fact that many contracts designate a specific "price" for the gas and, in addition, designate other expenses, such as taxes, for which the purchaser is responsible. They may provide for the reimbursement of severance taxes in a separate section. On the other hand, they may also be silent as to taxes or provide that the seller will pay all severance taxes.

The definition of "contract price" in section 105 reads:

> (c) Definition of Contract Price.— For purposes of this section, the term "contract price," when used with respect to any specific date, means—
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> (1) The price paid, per million Btu's under a contract for deliveries of natural gas occurring on such date; or
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> (2) If no deliveries of natural gas occurred under such contract on such date, the price, per million Btu's, that would have been paid had such deliveries occurred on such date.

We believe that the word "price" in the definition of "contract price," as well as the phrase "price under the terms of the existing contract" means the total amount of proceeds paid by the purchaser to obtain the subject gas. Therefore, the term "price" would include all proceeds paid or payable to the seller even if specifically earmarked as reimbursement for State severance taxes or production-related costs.[6]

Consequently, in determining the maximum lawful price under section 105 the total proceeds paid or payable on November 9, 1979, are to be compared to $2.06. If the total proceeds exceeds $2.06, then section 105(b)(2) applies. If not, then section 105(b)(1) applies. If section 105(b)(2) applies, then the total proceeds paid or payable on November 9, 1978, are used as the base to which the inflation adjustments of section 105(b)(2)(B) are applied. If section 105(b)(1) applies, then the total proceeds receivable under the contract may increase pursuant to the terms of the contract in effect on November 9, 1978, up to the section 102 level.

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[5] *See* note *1, supra.* Part 276, now issued as final regulations, implements a reporting system covering first sales under section 105, 106(b) and 109 of the NGPA.

[6] For example, if the contract provided as of November 9, 1979, for the payment of $1.50 and that buyer shall pay severance taxes (which amounts to 11 cents for that day), the contract price would be $1.61 because that is the total amount that the purchaser actually pays for the gas. However, if the seller were obligated to pay all taxes, then the contract price would be only $1.50—again the amount paid.

However, several parties inquired whether State severance taxes, as defined under section 110 of the NGPA, should be subtracted from the "contract price" on November 9, 1978. The comments focused on the Statement of Managers at page 90,[7] which, in the context of explaining section 110 of the NGPA,[8] states that all ceiling prices are "exclusive" of State severance taxes borne by the seller and certain production-related cost adjustments.[9] The commenters inquire whether the Manager's use of the term "exclusive" could indicate an intent that such items be subtracted from the contract price in order to compute ceiling prices under section 105.

The Commission does not interpret section 110 of the NGPA and the Statement of Managers at page 90 as requiring the subtraction of any expenditures referred to in section 110(a)(1) of the NGPA from any maximum lawful price under any section of Title I of the NGPA or, more particularly, from an intrastate "contract price" in order to establish the "ceiling price" under section 105. The words of the statute are clear: the price charged "will not be considered to exceed" the applicable maximum lawful price if the excess represents the amount "necessary to recover" State severance taxes "borne by the seller." What ambiguity exists in the Statement of Managers must be resolved in light of the plain meaning of the statute.

We believe that the Managers simply were indicating that ceiling prices were formulated without consideration of severance taxes, and logically so because severance taxes vary from state to state. Adjustments of ceiling prices to take account of severance taxes were to be considered only in the context of section 110.

Based on these general considerations, we do not find reason to reduce ceiling prices in general or prices under the terms of existing intrastate contracts in effect on date of enactment of the NGPA, in particular, by the amount representing State severance taxes levied on the production.[10] Furthermore, we do not believe that Congress intended such "contract prices" for existing intrastate contracts to be dissected. To do so would require that we dissect each existing intrastate contract price in order to excise certain of those reimbursed expenses, such as severance taxes. The emphasis Congress placed on negotiated prices in section 105 reflects the policy that historical contractural arrangements in the intrastate market were to be preserved. The NGPA and section 105 in particular were written so as to disturb contractual arrangements, for the most part, only minimally and only prospectively by limiting the rate of increases in prices subsequent to the date the NGPA was enacted. They should not be interpreted to involve retroactive downward adjustments of contract prices that were actually effective as of the date of enactment.

Acknowledging that State severance taxes should not be subtracted from the section 105 contract price, the question arises as to whether the seller may add the amount of any such taxes borne by him to the section 105 ceiling price under section 110 of the NGPA and under § 271.1102 of the Commission's regulations. This is the question which the Commission addresses in a notice of proposed rulemaking (RM80-21) which accompanies this final rule.

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[7] H.R. Rep. No. 95–1752, 95th Cong., 2d Sess. 90 (1978).

[8] Section 110(a) of the NGPA provides in pertinent part that "a price for the first sale of natural gas *shall not be considered to exceed the maximum lawful price* applicable to the first sale of such natural gas under this subtitle if such *first sale price* exceeds the maximum lawful price *to the extent necessary to recover* * * * State severance taxes * * * borne by the seller."

[9] As we shall explain in more detail, *infra* footnote 10, commenters have incorrectly created a link between the statement which refers to "ceiling prices" and the phrase "contract price" which is only partially determinative of the ceiling price in section 105 and is not, except in a limited number of cases, the same as the "ceiling price" in that section.

[10] Indeed there is no direct linkage between the explanation at page 90, which refers to "ceiling prices," and the suggestion that severance taxes should be subtracted from "contract prices" subject to section 105. While "contract prices" do play an integral role in the ceiling price computation mechanism of section 105, they do not necessarily constitute the "ceiling price" under that section. For example, while the price under a contract subject to section 105(b)(1) might rise above the section 102 level, the ceiling price under that section remains at the section 102 price.

We received one comment suggesting that the introductory language of § 271.504(a), which defines "contract price," be amended to read: "Contract price or prices paid * * *," since one contract may contain more than one price for different areas. We do not believe an amendment is necessary. However, we shall clarify our intent that the rules governing the determination of "contract price" apply to each separate price in a contract. Each sale is considered a separate sale under the NGPA and is to be regulated accordingly.

One comment requested clarification of the mechanism for determining maximum lawful prices under section 105 when certain section 102 sales (*i.e.*, new natural gas sales) are deregulated pursuant to section 121.[11] Section 105 keys maximum lawful prices to the relationship between contract prices and the section 102 price. However, reference to section 102 is used simply to provide a benchmark price for use in section 105. Therefore, the price mechanism in section 102(b) shall continue to be used to determine maximum lawful prices under section 105 (as well as section 102(d)) regardless of the impact of section 121.

C. *Contract Modifications—Section 105.* Many comments were received suggesting various amendments to § 271.505 to allow contract modifications to shift "production-related costs" to the purchaser. The comments characterized the suggested changes as a form of "special relief," similar to that provided in §§ 2.75 and 2.76 of the Commission's Regulations under the Natural Gas Act. Section 271.505 generally prohibits contract modifications that have the effect of shifting production-related costs, which are defined in § 271.1101 and section 110 of the NGPA, to the purchaser.

The comments suggested three situations in which it would be appropriate to provide special relief-type treatment in § 271.505: (1) installation of compression, cathodic protection, or treating facilities, (2) reworking wells or removal of water, and (3) recompletions, deeper drilling and new drilling.

The Commission issued on August 14, 1979 in Docket No. RM79-67 a Notice of Proposed Rulemaking relating to special relief under the NGPA. In that Notice we requested comments on whether the proposed special relief regulations can be extended to sections 102, 103, *105*, and 108 of the NGPA through use of our authority to specify maximum lawful prices for and to define "high cost natural gas" under section 107 or through use of section 110. Accordingly, we will defer decision on this issue and will resolve it within the context of the special relief proceeding.

Two sets of comments take contrary positions on the validity of the exception in § 271.505(b). Paragraph (b) of § 271.505 provides an exception to the general rule in paragraph (a) prohibiting contract modifications which shift production-related costs to the purchaser. In paragraph (b), we provided that a new purchaser could agree to pay for increased production-related costs in order to take delivery of the gas. One group alleges that § 271.505(b) discriminates against intrastate purchasers. The other group suggests that § 271.505(b) should be clarified or amended to allow contract amendments covering all future increases in production-related costs that are to be borne by the purchaser; *i.e.*, not just a one-time allowance to permit delivery of the gas. Notably, the latter group is comprised of interstate pipelines.

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[11] It should be noted that sales under section 102(d) are not deregulated under section 121.

We disagree with the suggestions of both groups. The purpose behind § 271.505(b) was to permit new purchasers to "hook up." No suggestion was made that a new intrastate pipeline purchaser could not take advantage of this rule. The only arguable discrimination in the rule is between new and old purchasers, not intrastate versus interstate purchasers. Accordingly, we shall retain § 271.505(b) in its present form. However, we wish to clarify that § 271.505(b) is intended to cover only the additional costs necessary for an initial hook-up with a new purchaser and not later increases in production-related costs. Once initial hookup is achieved and the new purchaser commences receipt of gas under the existing intrastate contract, there is no longer any reason to allow the seller to shift production-related costs to such a purchaser. It should be noted, however, that applications for adjustment may be made under § 271.1106 for allowance of production-related costs in cases of hardship, inequity, or unfair distribution of burdens.

One other comment questioned whether § 271.505(b), as well as § 271.604(b), is restricted to only those "production-related" costs required to physically take delivery to the exclusion of others such as the cost of installing conditioning facilities. Sections 271.505(b) and 271.604(b) are not so restrictive. For example, if new conditioning facilities must be installed to permit the changeover to a new purchaser,[12] then § 271.505(b) (or § 271.604(b), whichever is applicable) would permit the seller to shift to the new purchaser any obligation to pay for the new facilities. However, in that case the seller may not use a changeover to a new purchaser as a pretext to shift other "production-related" costs, such as costs of gathering that have not increased because of that changeover.

We caution that, while the special rules in §§ 271.505 and 271.604 relating to shifting production-related costs are issued and effective as final regulations, we may wish to reexamine these rules and the principles on which they are based when we deal with the question of final regulations under section 110 of the NGPA. We would also caution that these rules relate only to sections 105 and 106(b) of the NGPA and are not intended to impact on or circumscribe any policies or positions the Commission may take with respect to other sections of the NGPA or other acts.

Several comments were also received which suggested that, in any case in which an existing intrastate contract provides that the purchaser shall reimburse the seller for 85 percent of increased severance taxes, and in the event of such a tax increase, the parties should be allowed to amend the contract to provide for 100 percent reimbursement of such taxes. Section 271.1102, unless modified in accordance with the proposed rule which accompanies this final rule, permits full recovery of State severance taxes. Section 270.205(c) makes it clear that the NGPA does not prohibit contract modifications necessary in order to collect maximum lawful prices.

D. *Miscellaneous Comments on Subpart E.* One comment suggests that § 271.502(a)(1) be amended to read as follows:

> (1) The price for such month under the terms of the existing intrastate contract, *including the price determined by any fixed or indefinite price escalator clauses, including price redetermination provisions, contained in such existing contract,* to which such natural gas was subject on November 9, 1978, as such contract was in effect on November 9, 1978 * * *" (Added language italicized.)

This amendment is unnecessary in light of § 270.205(b), as issued in Order No. 23, which describes the operation of provisions in section 105 contracts governing changes in price.

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[12] For example, to meet more stringent quality standards.

Another comment suggests adding the word "if" before "required" in § 271.503 so that § 271.503 would read as follows:

> Any person who collects a price under this subpart shall file reports *if* required by § 276.101. (Added word italicized.)

This suggestion is rejected because under § 276.101, all first sellers are required to file reports under Part 276 even though the report may consist only of a title page and the attached oath statement.

It was suggested that the definition of "successor to an existing intrastate contract" in § 270.102(b)(9) be clarified to include successors that are interstate contracts. It was noted that the current definition is restricted to successor "intrastate" contracts. We believe that this suggestion has merit. An interstate contract may succeed an existing intrastate contract and in so doing become a "successor to an existing intrastate contract." Accordingly, we shall amend § 270.102(b)(9) to remove this restriction.

E. *Contract Modifications—Section 106(b).* Many commenters suggested that we should permit the modification of rollover contracts to allow for higher prices otherwise applicable under other sections of the NGPA, as well as add-ons permitted under section 110. This argument is identical to that made with respect to section 105 of the NGPA. With respect to recovery of State severance taxes, a rollover contract may provide for collection of the applicable maximum lawful price, including any allowance for State severance taxes permitted under section 110 of the NGPA. With respect to section 110 production-related cost allowances, the Commission's policy regarding section 106(b) is the same as its policy regarding section 105; *i.e.*, section 110 production-related cost allowances generally will not be permitted. With respect to contract modifications, the Commission addressed the issue in Order No. 23-A.[13] but restricted discussion in that order to section 105. However, the same principles discussed in Order No. 23-A apply with respect to section 106(b) gas. With regard to either the terms of the rollover contract as originally executed or any modifications in a rollover contract, the contractual provisions may not operate to authorize a seller to charge and collect an amount in excess of the applicable maximum lawful price. However, as in the case of existing intrastate contracts, a seller under an intrastate rollover contract is not bound by the maximum lawful price under that section when the gas otherwise qualifies for a higher maximum lawful price under another section of the NGPA Order No. 23-A promulgated § 270.205(c) which summarized these principles regarding "existing contracts." Section 270.205(c) will be amended in order to emphasize that the Commission wishes to apply this regulation to rollover contracts under section 106 as well as to any other contract.

The comments also suggested that Subpart F as well as Subpart E provide for special relief procedures; for example, provisions for higher prices to fund workovers or new drilling. Unlike section 105, subsection (c) of section 106 authorizes the Commission to establish higher "just and reasonable" prices for *any* sales under that section, including sales made under section 106(b). Accordingly, the mechanism for special relief is already provided for in section 106. As noted above, the Commission has issued a Notice of Proposed Rulemaking requesting comments on proposed regulations governing the granting of special relief under sections 104, 106 and 109 of the NGPA.

Several intrastate companies suggested that § 271.604(b), which provides an exception to the general rule in paragraph (a) prohibiting shifting production-related costs to new purchasers, creates the same unfair advantage for interstate pipelines as is created by § 271.505(b). The same answer obtains for the reasons discussed with respect to § 271.505(b). Section 271.604(b) only concerns a shifting of costs associated with the *initial* hook-up of a new purchaser. Contract modifications concerning subsequent, additional production-related costs will be prohibited under the general rule of paragraph (a) (except to the extent necessary to collect allowances for production-related costs which are permitted pursuant to an adjustment issued under § 271.1106).

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[13] Docket No. RM79-22. issued June 12, 1979.

Finally, one commenter mistakenly construed § 271.604(a) to prohibit any terms of a rollover contract from differing in any respect from those of the existing contract. This was not our intent. Section 271.604(a) relates to only those particular terms which deal with production-related costs. (*See* § 271.1105.)

F. *Definition of a "Rollover"—Section 106.* One commenter asks the following question: if an existing contract expires on a date certain but nevertheless would be indefinitely extended on a month to month basis unless cancelled by one of the parties, is the contract which is entered into after the prior contract is cancelled a rollover contract under section 106(b)? Other commenters ask the more general question: when does a rollover "occur" for purposes of section 106(b)(1)(A) of the NGPA?

Before we can define when a rollover "occurs," we must consider the definition of "rollover contract" in section 2(12) of the NGPA in light of the Statement of Managers. Section 2(12) of the NGPA defines a "rollover contract" as follows:

> The term "rollover contract" means any contract entered into on or after [November 9, 1978], for the first sale of natural gas that was previously subject to an existing contract which expired at the end of a fixed term (not including any extension thereof taking effect on or after [November 9, 1978]) specified by the provisions of such existing contract, as such contract was in effect on [November 9, 1978] whether or not there is an identity of parties or terms with those of such existing contract.

Section 2(12) requires several conditions before a contract can be deemed a rollover contract for purposes of section 106(b): (1) the rollover contract must be "entered into" on or after November 9, 1978; (2) the rollover contract must cover sales of gas "previously subject" to an "existing contract," *i.e.*, a contract in existence on November 8, 1978; and (3) the previous existing contract must have "expired" at the end of a "fixed term" pursuant to the provisions of the contract in effect on November 9, 1978, including fixed term extensions which took effect prior to that date.

Under the Natural Gas Act, a rollover contract was not "entered into" until the parties executed an extension of the contract's term or a new contract. Therefore a rollover could not occur until the fixed term of the existing contract expired, and the parties executed the extension of the new contract.[14] Section 2(12) of the NGPA could be read to make the definition of "rollover contract" consistent under both the NGPA and the NGA by requiring some affirmative action of the parties to effect a rollover.

However, language in the Statement of Managers at page 70, injects an element of confusion. At page 70, the Statement indicates that:

> An existing contract which expires at the end of a fixed term qualifies as a rollover contract. An existing contract may have a specified term of five years which will be extended by operation of the contract for one or more years unless the producer gives notice of his intention to terminate the contract within a specified period of time in advance. Such a contract will qualify as a rollover contract at the end of the fixed five year term without regard to the extensions occurring after the date of enactment.

Taken literally, this language suggests that a roll-over automatically occurs upon the expiration of the primary term of the existing intrastate contract. Thus, a rollover could occur even if the

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[14] See § 271.402(b) (3) and (4).

"existing contract" remained in existence by virtue of automatic "evergreen"-type contract term extensions,[15] and would not require some affirmative action on the part of the parties such as entering into a new contract or modifying the price terms.

The Commission interprets the Statement of Managers at page 70 as intended only to clarify the intent behind the parenthetical in section 2 (12), which reads:

> * * * "[R]ollover contract" means any contract, entered into * * * for the first sale of natural gas that was previously subject to an existing contract which expired at the end of a fixed term (*not including any extension thereof taking effect on or after such date of enactment*) * * *. (Emphasis added.)

The simplest reading of this parenthetical and the one which resolves rather than creates contradictions between the statute and the Statement of Managers suggests that a rollover can "occur" even if a contract term extension which took effect on or after November 9, 1978, has not yet expired. Therefore, as long as the fixed term of the existing contract (as may be extended prior to November 9, 1978) has expired and a new contract is "entered into" on or after November 9, 1978, the sales may become subject to maximum lawful prices under section 106(b) of the NGPA.

Accordingly, we shall define a "rollover" for purposes of section 106(b) to require that the fixed term of the "existing intrastate contract" must expire and a new contract or amendment must be entered into. A rollover may not "occur" until both prerequisites have been met.

These prerequisites apply equally to contracts containing evergreen clauses. Under evergreen clauses a rollover contract will not automatically occur merely upon expiration of the fixed term on or after November 9, 1978. The parties must take some action to enter into a new contract or contract amendment on or after November 9, 1978. However, especially with respect to intrastate contracts, we believe the characterization of such contracts as "existing," "successor," or "rollover" contracts requires close scrutiny of the contractual provisions as well as the timing of certain key events.[16] Accordingly, we are presenting here only the general principles to be followed in characterizing such contracts. Specific interpretations must be handled and may be requested pursuant to 18 CFR 1.42 on a case-by-case basis.

G. *Percentage-of-Proceeds Sales.* We have received requests for clarification of how percentage-of-proceeds sales[17] are to be regulated under Subparts E and F of Part 271. The Commission first focused on the status of such sales when faced with the question of how percentage sellers or purchasers were to report under Part 276. The following is an excerpt from the order promulgating final regulations under Part 276:

> In this regard we perceive the need to clarify how percentage sellers are to report their "contract price" on November 9, 1978, for purposes of Part 276 reports and oath statements. Percentage sale contracts have no specific price stipulated under the terms of the contract. Rather, they are generally based on the recovery of a fixed or volumetrically-determined percentage of net proceeds

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[15] "Evergreen clauses" provide that the term of the contract will be extended for some specified period beginning with the date of expiration of the primary term. The contract would remain in effect until terminated by action of one of the parties after giving the required notice prior to the anniversary date. Other variations of this type of clause also prevail in the industry.

[16] Gas subject to section 104 and 106(a) will continue to be subject to the requirement of execution of a new contract for amendment, so that the Commission may obtain adequate evidence of the parties' consent.

[17] The typical percentage-of-proceeds sales occur between a producer and a processing plant. The producer normally sells raw gas to the plant which, after processing it, sells the residue gas, which is of a lesser volume and BTU content than the raw gas, to a pipeline at the plant tailgate. Rather than receiving a fixed price for the gas, the producer recovers a percentage of the net proceeds received by the plant from the resale of gas and, perhaps, natural gas liquids.

> received from the sale at a plant tailgate of a mix of residue gas derived from many different producers. A "contract price" on November 9, 1978, might be computed by dividing sales volumes attributable to the percentage seller on that date. Such a computed "contract price" could change from day-to-day depending on various factors including the mix of resale prices at the plant tailgate and the price of liquids.
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> Accordingly, we find it appropriate to simplify the reporting of percentage proceeds sales by permitting the percentage received from the plant to be reported in lieu of a "contract price". Volumes to be reported shall be residue gas volumes.[18]

It appears that the NGPA did not specifically address the regulation of intrastate percentage-of-proceeds-sale contracts. The pricing mechanism under sections 105 and 106(b) appears to assume a specific price as stipulated by terms of the contract. A contract price for percentage of proceeds sales calculated on the basis of sales volumes attributable to the percentage seller on a given date does not appear to be within the scope of the term "contract price" as it is used in sections 105 and 106(b). In addition, nothing in the Statement of Managers indicates how first sales under such contracts that are subject to section 105 or 106(b) are to be regulated. Under these circumstances we believe the following to be the only practical course. Because resellers, usually processors or gatherers, are themselves regulated under the reseller rules contained in § 270.202, the same system of indirect regulation which has been used under the Natural Gas Act should be used to provide a pragmatic solution to this problem.[19] This will eliminate the problem of establishing "contract prices" in order to apply section 105 or 106(b) maximum lawful prices to sales to resellers. Moreover, under this procedure, no change in reporting obligations under Part 276 would be required.

The argument against indirect regulation is that each first sale, including percentage sales, is regulated at prices established by Congress. But as noted above, Congress gave no direction for applying maximum lawful prices under section 105 or 106(b) in the case of such percentage sales. As we recognized in our order promulgating final Part 276 regulations, it would simply be too arbitrary and burdensome to calculate contract prices on a continuous, even day-to-day basis.

Instead of attempting to impose such an arbitrary and burdensome method of establishing maximum lawful prices for such percentage-of-proceeds sales, we shall apply the maximum lawful price only to the sale by the reseller. As long as the reseller complies with the reseller rules of § 270.202(a)(1), the amount of proceeds received by the percentage-of-proceeds sellers will not affect the price paid by consumers. Because the percentage-of-proceeds sellers only receive a percentage (less than 100 percent) of the proceeds from the resale, the price of which may not exceed the applicable NGPA maximum lawful price, the total price received by these sellers as a group, cannot exceed the maximum lawful price. Distribution of proceeds derived from the resale of such gas will be deemed a matter of private contract law to be resolved by the parties. This policy is similar to that governing distribution of proceeds from a fixed-price sale by the operator of a well to the often numerous working interest owners. In order to effect this policy, we are adding a new subparagraph (3) to paragraph (e) of § 270.202 which defines "percentage-of-proceeds sale" and a new paragraph (h) to § 270.202. New paragraph (h) clarifies the rule that the resale of the portion of gas purchased under a percentage-of-proceeds sale subject to section 105 or 106(b) is governed by § 270.202(a) and that such percentage sales will not be deemed to be first sales for purposes of Subchapter H. We wish to emphasize that, for administrative purposes, we will not attempt to apply the section 105 and 106(b) ceiling price provisions at the point of the percentage-of-proceeds sale. Rather we shall focus on the point of resale. We are not, however, creating any general exemption from the NGPA for such percentage sales.

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[18] Final Part 276 Regulation Under the Natural Gas Policy Act of 1978, Docket No. RM79-30, Order Amending Part 276, Issuing Part 276 as Final Regulations and Promulgating FERC Forms 122, 123, and 124 and Accompanying Affidavits and Instructions, (issued March 23, 1979, 44 FR 18647) at mimeo pages 12-13 (44 FR 18649).

[19] *See.* 18 CFR 254.91(e).

Although we have discussed only intrastate sales subject to section 105 or 106(b) of the NGPA we believe that the amendment to the reseller rules that we promulgate in new paragraph (h) to § 270.202, should also apply to interstate percentage-of-proceeds sales which are subject to § 154.91(e) of the Commission's Regulations under the Natural Gas Act. Because such sales are already only indirectly regulated, no modification of our Natural Gas Act regulations is required.

III. Summary of Amendments

The following amendments have been made to the interim rules:

A definition and special rules for percentage-of-proceeds sales have been added to § 270.202. The maximum lawful price for a percentage-of-proceeds sale is applicable at the point the gas is sold by the reseller.

All references to "existing" contracts have been deleted from § 270.205(c), so that the paragraph applies to all sales and permits sellers to modify any contract to collect any applicable NGPA prices other than section 105(b)(1) gas which does not also qualify for another maximum lawful price set by reference to the contract price.

The determinations of contract price and the price under the terms of the existing contract have been clarified by an amendment to § 271.504 to reflect the effect of State severance taxes.

The definition of "successor to an existing intrastate contract" at § 271.102 has been corrected to clarify the fact that successors to existing intrastate contracts include interstate contracts.

Paragraph (b) of § 271.602 has been corrected to include a reference to State or Indian royalty interests as well as production interests.

IV. Public Procedures and Effective Date

Parts 270 and 271 were originally proposed for comment in November of 1978 and issued as interim regulations on December 1, 1978 (43 FR 56448; December 1, 1978). For 60 days thereafter comments were received and during that period public hearings were held on these regulations. By this process the Commission complied with the provision of section 502(b) of the NGPA which requires that "[t]o the maximum extent practicable, an opportunity for oral presentation of data, views, and arguments" be afforded for certain regulations under the NGPA.

The amendments to Part 270 and Subparts E and F of Part 271 contained in this order rest upon considerations given to the information received during the comment and hearing process. Therefore, the Commission believes that no further notice of public procedure is required under 5 U.S.C. 553.

(Natural Gas Act, as amended, 15 U.S.C. 717, *et seq.*; Department of Energy Organization Act, 47 U.S.C. 7101-7352; E.O. 12009, 42 FR 46267; Natural Gas Policy Act of 1978; 15 U.S.C. 3301-3432)

In consideration of the foregoing, the interim regulations in Part 270, Subchapter H, Chapter I of Title 18, Code of Federal Regulations, are amended as set forth below. In addition, Subparts E and F of Part 271 are amended and issued as final regulations as set forth below. These amendments are effective with respect to natural gas delivered on or after December 1, 1978, except that the application of the effective date shall not cause the impositon of any refund obligation with respect to any deliveries made prior to February 15, 1980.

By the Commission.
Kenneth F. Plumb,
Secretary.

[¶ 30,126]

45 F. R. 6376 (January 23, 1980)

18 CFR Part 3

[Docket No. RM79-59; Order]

Regulations Amending Rules Relating to Delegations of the Commission's Authority to the Director of the Office of Electric Power Regulation

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts regulations which delegate to the Director of the Office of Electric Power Regulation the authority to grant or deny uncontested applications for exemptions, extensions and withdrawal petitions pursuant to section 133 of the Public Utility Regulatory Policies Act of 1978 (Pub. L. 95-617) (18 CFR 290.601, 290.602, 290.603).

DATES: Effective date—January 23, 1980. Comment date—February 8, 1980.

FOR FURTHER INFORMATION CONTACT: Tom Runge, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Room 3329, Washington, D.C. 20426; (202) 357-8318.

January 23, 1980.

A. Background

On August 14, 1978, the Commission approved a rulemaking, Delegations of Authority (Phase I), Docket No. RM78-1[illegible], 43 FR 36433, which served to transfer decision-making authority for decisions of a largely routine and ministerial nature downward within the Commission, to its various office directors, so that the Commission can concentrate its major efforts on issues of greater significance. The decisional responsibility for perhaps as many as 7,000 decisions annually was delegated to the office directors under that rule. Subsequently, on July 23, 1979, the Commission added to these delegations by adopting additional ones, in the Phase II Delegation, Docket No. RM79-59, 44 FR 46449 (August 8, 1979).

As a continuation of this process, the Commission has decided to approve a further delegation of authority to the Director of the Office of Electric Power Regulation.

The authority to be delegated arises under section 133 of the Public Utility Regulatory Policies Act of 1978 (PURPA), Pub. L. 95-617, which requires electric utilities to gather information on costs of electric service, and file that information with the Commission. The Commission is granted broad authority in section 133 to specify by rule the type of information to be gathered, and the manner in which these data are to be filed and published.

Pursuant to this statutory mandate, the Commission issued on September 28, 1979, final regulations implementing section 133. Order No. 48, 44 FR 58687 (October 11, 1979).

These final regulations, 18 CFR 290, authorize the Commission, *inter alia*, to grant exemptions from the section 133 requirements, 18 CFR 290.601; to grant extensions of deadlines for filing certain data, 18 CFR 290.602; and to grant petitions for withdrawals of exemptions and extensions, 18 CFR 290.603.

It is these three authorities—the power to grant exemptions, extensions, and withdrawal petitions pursuant to 18 CFR 290.601, 290.602, and 290.603—that are hereby delegated to the Director of the Office of Electric Power Regulation.

There are two important qualifications to the Director's exercise of these delegated authorities: First, the Director may grant or deny the application for the exemption, extension, or withdrawal petition only if it is "uncontested". "Uncontested" means, pursuant to 18 CFR 1.1(f)(23), that no petition for, or notice of, intervention in opposition to the application has been made under 18 CFR 1.8 and received by the Commission. In sum, receipt of an intervention in opposition to the application serves to terminate the Director's authority to determine the application, and brings the application directly before the Commission.

Second, as is true of all other exercises of delegated authority, "any interested person" may, pursuant to 18 CFR 1.7, appeal the Director's decision.

This rule is based upon the authority granted the Commission in section 401(f) of the Department of Energy Organization Act, Pub.L. 95–91, "to establish such procedural and administrative rules as are necessary to the exercise of its functions."

B. Summary

Under new 18 CFR 3.5(g)(37), there is delegated to the Director of the Office of Electric Power Regulation the authority to grant or deny uncontested applications for exemptions, extensions, and withdrawal petitions pursuant to 18 CFR 290.601, 290.602, and 290.603.

C. Effective Date

The Commission hereby makes this regulation effective upon the date of issuance of this order. The regulation concerns agency practice and procedure; accordingly, pursuant to 5 U.S.C. 553 (b) and (d), public notice and comments are not required, and the regulation may be promulgated, effective immediately. The Commission, nevertheless, invites interested members of the public to submit comments regarding this new delegation. The Commission and its staff will evaluate any information received from interested persons and will consider appropriate revisions to this regulation based on comments received. An original and 14 copies should be filed by February 8, 1980, with the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426. All comments should refer, on the cover page, to Docket No. RM79–59.

(Department of Energy Organization Act, 42 U.S.C. 7107 *et seq.*; Public Utility Regulatory Policies Act, Pub. L. 95–617).

For the reasons stated herein, Part 3 of Subchapter A of Chapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,127]

45 F. R. 7781 (February 5, 1980)

18 CFR Part 271

[Docket No. RM80-23]

Ceiling Prices, Publication of Prescribed Maximum Lawful Prices Under the Natural Gas Policy Act of 1978; Amendments to Final Regulations

Issued: January 29, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: This rule amends § 271.101(a) of the Federal Energy Regulatory Commission's regulations implementing the Natural Gas Policy Act of 1978 (NGPA). By this amendment, the Commission publishes the Maximum Lawful Prices under the NGPA for the months of February, March and April of 1980. Section 101(b)(6) of the NGPA requires that the Commission compute and make available prices and inflation adjustments before the beginning of any month for which such figures apply.

EFFECTIVE DATE: January 29, 1980.

FOR FURTHER INFORMATION CONTACT: Mark G. Magnuson, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357–8511.

A. Background

Section 101(b)(6) of the NGPA requires that the Commission compute and make available maximum lawful prices and inflation adjustments before the beginning of any month for which such figures apply. Pursuant to that mandate, the Commission is amending its regulations implementing the NGPA to issue the maximum lawful prices for the months of February, March and April of 1980, by the publication of price tables for the applicable quarter.

Table I specifies the maximum lawful prices for gas subject to sections 102, 103, 106(b)(1)(B), 107, 108 and 109 of the NGPA. Table II specifies the prices for section 104 and 106(a); Table III sets forth the inflation adjustments.

B. Summary of Amended Regulations

The Commission's regulations under the NGPA are being amended by the publication of Tables I, II, and III establishing the maximum lawful prices and inflation adjustment factors for February, March and April of 1980. This amendment affects the Subpart A of Part 271, entitled:

"Summary Tables and Calculations" (§§ 271.101(a) and 271.102(c)).

C. Public Procedure and Effective Date

The Commission is making these amendments effective upon the date of issuance of this order upon a finding that it is impractical and unnecessary to comply with the notice and public procedure provisions of 5 U.S.C. 533. Section 101(b)(6) of the NGPA requires that maximum lawful prices and inflation adjustments be made available by the Commission before the beginning of the month to which they apply. However, publication of the GNP Implicit Price Deflator by the Department of Commerce at least 8 days before the most recent calendar quarter, does not provide sufficient time for comment before the maximum lawful prices and inflation adjustments go into effect. Notice and public comment are unnecessary as well as impractical because the changes do not change the substance of the regulations and because the changes in prices and inflation adjustments are mandated by statute. Good cause exists to make these amendments regarding the rate changes for February, March and April of 1980, effective immediately. Such a procedure is required in order to comply with the NGPA, and, if such a procedure is not followed, producers may bill and file incorrectly for the affected categories of gas.

(Natural Gas Act, as amended, 15 U.S.C. § 717 *et seq.;* Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350; Department of Energy Organization Act, 42 U.S.C. § 7107, *et seq.,* E.O. 12009, 42 FR 46267)

In consideration of the foregoing, Part 271 of Subchapter H, Chapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,128]

45 F. R. 12214 (February 25, 1980); 45 F. R. 24126 (April 9, 1980)

18 CFR Part 292

[Docket No. RM79-55, Order No. 69]

Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts regulations that implement section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA). The rules require electric utilities to purchase electric power from and sell electric power to qualifying cogeneration and small power production facilities, and provide for the exemption of qualifying facilities from certain federal and State regulation. Implementation of these rules is reserved to State regulatory authorities and nonregulated electric utilities.

EFFECTIVE DATE: March 20, 1980.

FOR FURTHER INFORMATION CONTACT:

Ross Ain, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, 202-357-8446.
John O'Sullivan, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, 202-357-8477.
Adam Wenner, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, 202-357-8033.
Bernard Chew, Office of Electric Power Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, 202-376-9264.

SUPPLEMENTARY INFORMATION:
Issued February 19, 1980.

Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) requires the Federal Energy Regulatory Commission (Commission) to prescribe rules as the Commission determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from and sell electric power to cogeneration and small power production facilities. Additionally, section 210 of PURPA authorizes the Commission to exempt qualifying facilities from certain Federal and State law and regulation.

Under section 201 of PURPA, cogeneration facilities and small power production facilities which meet certain standards and which are not owned by persons primarily engaged in the generation or sale of electric power can become qualifying facilities, and thus become eligible for the rates and exemptions set forth under section 210 of PURPA.

Cogeneration facilities simultaneously produce two forms of useful energy, such as electric power and steam. Cogeneration facilities use significantly less fuel to produce electricity and steam (or other forms of energy) than would be needed to produce the two separately. Thus, by using fuels more efficiently, cogeneration facilities can make a significant contribution to the Nation's effort to conserve its energy resources.

Small power production facilities use biomass, waste, or renewable resources, including wind, solar amd water, to produce electric power. Reliance on these sources of energy can reduce the need to consume traditional fossil fuels to generate electric power.

Prior to the enactment of PURPA, a cogenerator or small power producer seeking to establish interconnected operation with a utility faced three major obstacles. First, a utility was not generally required to purchase the electric output, at an appropriate rate. Secondly, some utilities charged discriminatorily high rates for back-up service to cogenerators and small power producers. Thirdly, a cogenerator or small power producer which provided electricity to a utility's grid ran the risk of being considered an electric utility and thus being subjected to State and Federal regulation as an electric utility.

Sections 201 and 210 of PURPA are designed to remove these obstacles. Each electric utility is required under section 210 to offer to purchase available electric energy from cogeneration and small power production facilities which obtain qualifying status under section 201 of PURPA. For such purchases, electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, in the public interest, and which do not discriminate against cogenerators or small power producers. Section 210 also requires electric utilities to provide electric service to qualifying facilities at rates which are just and reasonable, in the public interest, and which do not discriminate against cogenerators and small power producers. Section 210(e) of PURPA provides that the Commission can exempt qualifying facilities from State regulation regarding utility rates and financial organization, from Federal regulation under the Federal Power Act (other than licensing under Part I), and from the Public Utility Holding Company Act.

I. Procedural History

On June 26, 1979, in Docket No. RM79–54,[1] the Commission issued proposed rules to determine which cogeneration and small power production facilities may become "qualifying" cogeneration or small power production facilities under section 201 PURPA. Such qualifying facilities are entitled to avail themselves of the rate and exemption provisions under section 210 of PURPA; and qualifying cogeneration facilities are eligible for exemption from incremental pricing under Title II of the Natural Gas Policy Act of 1978.[2] The Commission will soon issue a final rule in Docket No. RM79–54.

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[1] 44 FR 38873, July 3, 1979.

[2] 44 FR 65744, November 15, 1979.

As part of the rulemaking process in this docket, the Commission issued a Staff Discussion Paper[3] on June 27, 1979, addressing issues arising under section 210 of PURPA.

Public hearings on RM79–54 and the Staff Discussion Paper (RM79–55) were held in San Francisco on July 23, 1979, Chicago on July 27, 1979, and Washington, D.C. on July 30, 1979. Written comments were also received.

On October 18, 1979, the Commission issued a Notice of Proposed Rulemaking under Section 210 of PURPA in Docket No. RM79–55.[4] On October 19, 1979, the Commission made available its preliminary Environmental Assessment (EA) of the proposed rules in Docket Nos. RM79–54 and RM79–55. In a Request for Further Comments,[5] the Commission requested further public comment on both proposed rules, and on the findings set forth in the preliminary EA. In order to obtain the data, views, and arguments of interested parties, the Commission Staff held public hearings in Seattle on November 19, 1979, in New York on November 28, 1979, in Denver on November 30, 1979, and in Washington, D.C. on December 4 and 5, 1979. The Commission also received written comment.

After consideration of the comments, the Commission Staff made available a final draft rule on January 29, 1980. State public utility commissioners were invited to comment on the draft at a public meeting held on February 5, 1980. Representatives of electric utilities were invited to comment at a public meeting held on February 8, 1980. The Commission Staff also made itself available to any other interested parties who wished to comment. All of the comments were considered in the formulation of this final rule.

In the Staff Discussion Paper and the Request for Further Comments, it was stated that any environmental effects attributable to this program would result from the combined effect of these two rulemaking proceedings. As noted previously, the Commission intends to issue final rules in Docket No. RM79–54 in the near future. At that time, the Commission will also make available its final Environmental Assessment.

II. Summary

These rules provide that electric utilities must purchase electric energy and capacity made available by qualifying cogenerators and small power producers at a rate reflecting the cost that the purchasing utility can avoid as a result of obtaining energy and capacity from these sources, rather than generating an equivalent amount of energy itself or purchasing the energy or capacity from other suppliers. To enable potential cogenerators and small power producers to be able to estimate these avoided costs, the rules require electric utilities to furnish data concerning present and future costs of energy and capacity on their systems.

These rules also provide that electric utilities must furnish electric energy to qualifying facilities on a nondiscriminatory basis, and at a rate that is just and reasonable and in the public interest; and that they must provide certain types of service which may be requested by qualifying facilities to supplement or back up those facilities' own generation.

The rule exempts all qualifying cogeneration facilities and certain qualifying small power production facilities from certain provisions of the Federal Power Act, from all of the provisions of the Public Utility Holding Company Act of 1935 related to electric utilities, and from State laws regulating electric utility rates and financial organization.

The implementation of these rules is reserved to the State regulatory authorities and nonregulated electric utilities. Within one year of the issuance of the Commission's rules, each State regulatory authority or nonregulated utility must implement these rules. That implementation may be accomplished by the issuance of regulations, on a case-by-case basis, or by any other means reasonably designed to give effect to the Commission's rules.

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[3] 44 FR 38863, July 3, 1979.

[4] 44 FR 61190, October 24, 1979.

[5] 44 FR 61977, October 29, 1979.

III. Section-by-Section Analysis

Subpart A—General Provisions

§ *292.101 Definitions.*

This section contains definitions applicable to this part of the Commission's rules. Paragraph (a) provides that terms defined in PURPA have the same meaning as they have in PURPA, unless further defined in this part of the Commission's regulations. The definitions in PURPA are found in section 3 of that Act.

Subparagraph (1) defines a qualifying facility as a cogeneration or small power production facility which is a qualifying facility under Subpart B of the Commission's regulations. Those regulations implement section 201 of PURPA, and are the subject of Docket No. RM79-54.

Subparagraph (2) defines "purchase" as the purchase of electric energy or capacity or both from a qualifying facility by an electric utility.

Subparagraph (3) defines "sale" as the sale of electric energy or capacity or both by an electric utility to a qualifying facility.

In the proposed rule, subparagraph (4) defined "system emergency" as a condition on a utility's system "which is likely to result in disruption of service to a significant number of customers or is likely to endanger life or property." In response to comments noting the difficulty in determining what constitutes a "significant number" of customers, the Commission has amended the definition to "a condition on an electric utility's system which is likely to result in imminent significant disruption of service to customers, or is imminently likely to endanger life or property." The emphasis is placed on the significance of the disruption of service, rather than on the number of customers affected.

Subparagraph (5) defines "rate" as any price, rate, charge, or classification made, demanded, observed or received with respect to the sale or purchase of electric energy or capacity, or any rule, regulation, or practice respecting any such rate, charge, or classification, and any contract pertaining to the sale or purchase of electric energy or capacity.

In the proposed rule, subparagraph (6) defined "avoided costs" as the costs to an electric utility of energy or capacity or both which, but for the purchase from a qualifying facility, the electric utility would generate or construct itself or purchase from another source. This definition is derived from the concept of "the incremental cost to the electric utility of alternative electric energy" set forth in section 210(d) of PURPA. It includes both the fixed and the running costs on an electric utility system which can be avoided by obtaining energy or capacity from qualifying facilities.

The costs which an electric utility can avoid by making such purchases generally can be classified as "energy" costs or "capacity" costs. Energy costs are the variable costs associated with the production of electric energy (kilowatt-hours). They represent the cost of fuel, and some operating and maintenance expenses. Capacity costs are the costs associated with providing the capability to deliver energy; they consist primarily of the capital costs of facilities.

If, by purchasing electric energy from a qualifying facility, a utility can reduce its energy costs or can avoid purchasing energy from another utility, the rate for a purchase from a qualifying facility is to be based on those energy costs which the utility can thereby avoid. If a qualifying facility offers energy of sufficient reliability and with sufficient legally enforceable guarantees of deliverability to permit the purchasing electric utility to avoid the need to construct a generating unit, to build a smaller, less expensive plant, or to reduce firm power purchases from another utility, then the rates for such a purchase will be based on the avoided capacity and energy costs.

The Commission has added the term "incremental" to modify the costs which an electric utility would avoid as a result of making a purchase from a qualifying facility. Under the principles of economic dispatch, utilities generally turn on last and turn off first their generating units with the highest running cost. At any given time, an economically dispatched utility can avoid operating its highest-cost units as a result of making a purchase from a qualifying facility. The utility's avoided incremental costs (and not average system costs) should be used to calculate avoided costs. With regard to capacity, if a purchase from a qualifying facility permits the utility to avoid the addition of new capacity, then the avoided cost of the new capacity and not the average embedded system cost of capacity should be used.

Many comments noted that the definition of "avoided cost" in the proposed rule failed to link the capacity costs which a utility might avoid as a result of purchasing electric energy or capacity or both from a qualifying facility with the energy costs associated with the new capacity. If the Commission required electric utilities to base their rates for purchases from a qualifying facility on the high capital or capacity cost of a base load unit and, in addition, provided that the rate for the avoided energy should be based on the high energy cost associated with a peaking unit, the electric utilities' purchased power expenses would exceed the incremental cost of alternative electric energy, contrary to the limitation set forth in the last sentence of section 210(b).

One way of determining the avoided cost is to calculate the total (capacity and energy) costs that would be incurred by a utility to meet a specified demand in comparison to the cost that the utility would incur if it purchased energy or capacity or both from a qualifying facility to meet part of its demand, and supplied its remaining needs from its own facilities. The difference between these two figures would represent the utility's net avoided cost. In this case, the avoided costs are the excess of the total capacity and energy cost of the system developed in accordance with the utility's optimal capacity expansion plan,[6] *excluding* the qualifying facility, over the total capacity and energy cost of the system (before payment to the qualifying facility) developed in accordance with the utility's optimal capacity expansion plan *including* the qualifying facility.[7]

Subparagraph (7) defines "interconnection costs" as the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs.

The Commission has clarified this definition to include distribution and administrative costs associated with the interconnected operation, in response to comments indicating that the proposed rule was vague in these respects. This definition is designed to provide the State regulatory authorities and nonregulated electric utilities with the flexibility to ensure that all costs which are shown to be reasonably incurred by the electric utility as a result of interconnection with the qualifying facility will be considered as part of the obligation of the qualifying facility under § 292.306. These costs may include, but are not limited to, operating and maintenance expenses, the costs of installation of equipment elsewhere on the utility's system necessitated by the interconnection, and reasonable insurance expenses. However, the Commission does not expect that litigation expenses incurred by the utility involving this section will be considered a legitimate interconnection cost to be borne by the qualifying facility.

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[6] An optimal capacity expansion plan is the schedule for the addition of new generating and transmission facilities which, based on an examination of capital, fuel, operating and maintenance costs, will meet a utility's projected load requirements at the lowest total cost.

[7] Throughout the rule and preamble, the phrase "energy or capacity" is used. This phrase is intended to include the capacity and energy costs associated with the capacity, if the purchase involves both energy or capacity.

Certain interconnection costs may be incurred as a result of sales from a utility to a qualifying facility. The Commission notes that the Joint Explanatory Statement of the Committee of Conference (Conference Report) prohibits the use of "unreasonable rate structure impediments, such as unreasonable hook up charges or other discriminatory practices . . ." [8] This prohibition is reflected in § 292.306(a) of these rules, which provides that interconnection costs must be assessed on a nondiscriminatory basis with respect to other customers with similar load characteristics.

A qualifying facility which is already interconnected with an electric utility for purposes of sales may seek to establish interconnection for the purpose of utility purchases from the qualifying facility. In this case, the qualifying facility may have compensated the utility for its interconnection costs with respect to sales to the qualifying facility, either as part of the utility's demand or energy charges, or through a separate customer charge. If this is the case, the interconnection costs associated with the purchase include only those additional interconnection expenses incurred by the electric utility as a result of the purchase, and do not include any portion of the interconnection costs for which the qualifying facility has already paid through its retail rates.

One comment recommended that the definition be revised to cover "all identifiable costs, including but not limited to, the costs of interconnection . . . resulting from interconnected operation". The Commission rejects this suggestion in order to maintain consistency with its initial determination to separate the utility's avoided costs with regard to purchases from qualifying facilities, from the costs incurred as a result of interconnection with a qualifying facility. Accordingly, legitimate costs not recovered pursuant to this section can be netted out in the calculation of avoided costs.

This definition also incorporates the concept from the proposed rule, as clarified in an erratum notice,[9] that these costs are limited to the net increased interconnection costs imposed on an electric utility compared to those interconnection costs it would have incurred had it generated the energy itself or purchased an equivalent amount of energy or capacity from another source.

This section of the rule contains definitions of "supplementary power", "back-up power", "interruptible power", and "maintenance power" which did not appear in the proposed rule.

Subparagraph (8) defines "supplementary power" as electric energy or capacity, supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generates itself.

Subparagraph (9) defines "back-up power" as electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

Subparagraph (10) defines "interruptible power" as electric energy or capacity supplied by an electric utility subject to interruption by the electric utility under specified conditions.

Subparagraph (11) defines "maintenance power" as electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility.

Subpart C—Arrangements Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities Under Section 210 of the Public Utility Regulatory Policies Act of 1978

§ *292.301 Scope.*

Section 292.301(a) describes the scope of Subpart C of Part 292 of the Commission's rules. Subpart C applies to sales and purchases of electric energy or capacity between qualifying cogeneration or small power production facilities and electric utilities, and actions related to such sales and purchases. Section 292.301(b)(1) provides that this subpart does not preclude negotiated agreements between qualifying cogenerators or small power producers and electric utilities which differ from rates, or terms or conditions which would otherwise be required under the subpart. Paragraph (b)(2) states that this subpart does not affect the validity of any contract entered into between a qualifying facility and an electric utility for any purchase.[10]

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[8] Conference Report on H.R. 4018, Public Utility Regulatory Policies Act of 1978, H. Rep. No. 1750, 98, 95th Cong., 2d Sess. (1978).

[9] 44 FR 63114, November 2, 1979.

Paragraph (b)(1) reflects the Commission's view that the rate provisions of section 210 of PURPA apply only if a qualifying cogenerator or small power production facility chooses to avail itself of that section. Agreements between an electric utility and a qualifying cogenerator or small power producer for purchases at rates different than rates required by these rules, or under terms or conditions different from those set forth in these rules, do not violate the Commission's rules under section 210 of PURPA. The Commission recognizes that the ability of a qualifying cogenerator or small power producer to negotiate with an electric utility is buttressed by the existence of the rights and protections of these rules.

Some comments stated that paragraph (b)(2) would unfairly penalize cogenerators and small power producers who, prior to the promulgation of these regulations, entered into binding contracts with electric utilities under less favorable terms than might be obtainable under these rules. The Commission interprets its mandate under section 210(a) to prescribe "such rules as it determines necessary to encourage cogeneration and small power production * * *" to mean that the total costs to the utility and the rates to its other customers should not be greater than they would have been had the utility not made the purchase from the qualifying facility or qualifying facilities. That a cogeneration or small power production facility entered into a binding contractual arrangement with an electric utility indicates that it is likely that sufficient incentive existed, and that the further encouragement provided by these rules was not necessary. As a result, the Commission has not revised this provision.

§ 292.302 Availability of electric utility system cost data.

As the Commission observed in the Notice of Proposed Rulemaking, in order to be able to evaluate the financial feasibility of a cogeneration or small power production facility, an investor needs to be able to estimate, with reasonable certainty, the expected return on a potential investment before construction of a facility. This return will be determined in part by the price at which the qualifying facility can sell its electric output. Under § 292.304 of these rules, the rate at which a utility must purchase that output is based on the utility's avoided costs, taking into account the factors set forth in paragraph (e) of that section. Section 292.302 of these rules is intended by the Commission to assist those needing data from which avoided costs can be derived. It requires electric utilities to make available to cogenerators and small power producers data concerning the present and anticipated future costs of energy and capacity on the utility's system.

In the preamble to the proposed rule, the Commission stated that most electric utilities will have prepared data containing some of this information in compliance with the Commission's rules implementing section 133 of PURPA. Several commenters observed that the marginal cost data required to be provided pursuant to section 133 cannot be directly translated into a rate for purchases. The Commission has clarified paragraph (b) to emphasize that these data are not intended to represent a rate for purchases from qualifying facilities. Rather, these data are to be considered the first step in the determination of such a rate.

The Commission has also revised this section so that the rates for purchases can be more readily calculated from the data produced. The Commission has changed paragraph (b)(3) to provide that a utility shall submit the associated energy cost of each planned unit expressed in kilowatt-hours (kWh) along with the estimated capacity cost of planned capacity additions. This change is intended to ensure that the calculation of avoided costs includes the lower energy costs that might be associated with the new capacity. The Commission points out that the determination of a rate for purchases from a qualifying facility which enables a utility to defer or avoid the addition of a new unit must also reflect the hours of expected use of the deferred or avoided capacity addition.

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[10] The term "purchase" is defined in § 292.101(b).

The coverage under paragraph (a) of this section is the same as that provided pursuant to section 133 of PURPA and the Commission's rules implementing that section.[11] As noted in the Notice of Proposed Rulemaking, section 133 of PURPA applies to each electric utility whose total sales of electric energy for purposes other than resale exceeded 500 million kWh during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year.

Paragraph (b) provides that each regulated electric utility meeting the requirements of paragraph (a) must furnish to its State regulatory authority, and maintain for public inspection, data related to the costs of energy and capacity on the electric utility's system. Each nonregulated electric utility also must maintain such data for public inspection.

In response to comments received, the Commission has extended the date by which these data must be first provided to November 1, 1980, and changed the second date to May 31, 1982, to conform to the dates required by the Commission's regulations implementing section 133 of PURPA. The Commission has added paragraph (d) to allow a State regulatory authority or nonregulated utility to use a different approach than that provided in paragraph (b). As part of that substitute program, a State regulatory authority or nonregulated electric utility could provide that cost data be updated more frequently than every two years.

Subparagraph (1) of paragraph (b) requires each electric utility to provide the estimated avoided cost of energy on its system for various levels of purchases from qualifying facilities. The levels of purchases are to be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than ten percent of system peak demand for systems less than 1000 megawatts. This information is to be stated on a cents per kilowatt-hour basis, for daily and seasonal peak and off-peak periods, for the current calendar year and for each of the next five years.

Subparagraph (2) of paragraph (b) requires each electric utility to provide its schedule for the addition of capacity, planned purchases of firm energy and capacity, and planned capacity retirements for each of the next ten years.

Subparagraph (3) of paragraph (b) has been revised, as discussed previously, so that the costs of planned capacity additions include the associated energy costs.

The Commission received comment noting that some States have implemented or are planning to implement alternative methods by which electric utilities' system cost data would be made available. In order to prevent the preparation of duplicative data where the alternative method substantially deviates from the Commission approach, the Commission has added paragraph (d). This paragraph provides that any State regulatory authority or nonregulated electric utility may, after providing public notice in the area served by the utility and after opportunity for public comment, require data different than that which are otherwise required by this section if it determines that avoided costs can be derived from such data. Any State regulatory authority or nonregulated utility shall notify the Commission within 30 days of any determination to sustitute data requirements.

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[11] 44 FR 58687, October 11, 1979.

If a qualifying facility finds that the alternative requirements do not provide sufficient data from which avoided costs may be derived, the qualifying facility may seek court review of the matter as it can with regard to any other aspect of the State's implementation of this program.

A qualifying facility may wish to sell energy or capacity to an electric utility which is not subject to the reporting requirements of paragraph (b). In that event, paragraph (c) provides that, upon request of a qualifying facility, an electric utility not otherwise covered by paragraph (b) must provide data sufficient to enable the cogenerator or small power producer to estimate the utility's avoided costs. If such utility does not supply the requested data, the qualifying facility may apply to the State regulatory authority which has ratemaking authority over the utility or to this Commission for an order requiring that the information be supplied. The consideration of such applications should take into account the burden imposed on the small utilities.

An electric utility which is legally obligated to obtain all of its requirements for electric energy and capacity from another utility may provide the data provided by its supplying utility and the rates at which it currently purchases such energy and capacity for any period during which this obligation will continue. The wholesale rates may require adjustment in order to reflect properly the avoided costs. This is discussed later in this preamble under § 292.303. In the case of small, non-generating utilities, the requirements of this section will be considered to have been satisfied if these cost data are readily available from the supplying utility.

Numerous comments mentioned that the proposed rule did not address the issue of validation of the data to be provided pursuant to this section. As a result, the Commission has added paragraph (e) which provides that any data submitted by an electric utility under this section shall be subject to review by its State regulatory authority. Paragraph (e)(2) places the burden of providing support for the data on the utility supplying the data.

§ 292.303 Electric utility obligations under this subpart.

Section 210(a) of PURPA provides that the Commission prescribe rules requiring electric utilities to offer to purchase electric energy from qualifying facilities. The Commission interprets this provision to impose on electric utilities an obligation to purchase all electric energy and capacity made available from qualifying facilities with which the electric utility is directly or indirectly interconnected, except during periods described in § 292.304(f) or during system emergencies.

A qualifying facility may seek to have a utility purchase more energy or capacity than the utility requires to meet its total system load. In such a case, while the utility is legally obligated to purchase any energy or capacity provided by a qualifying facility, the purchase rate should only include payment for energy or capacity which the utility can use to meet its total system load. These rules impose no requirement on the purchasing utility to deliver unusable energy or capacity to another utility for subsequent sale.

§ 292.303(a) Obligation to purchase from qualifying facilities.

§ 292.303(d) Transmission to other electric utilities. All-Requirement Contracts.

Several commenters noted that the obligation to purchase from qualifying facilities under this section might conflict with contractual commitments into which they had entered requiring them to purchase all of their requirements from a wholesale supplier. One commenter noted that, with regard to all-requirements rural electric cooperatives, any impairment of the obligation to obtain all of a cooperative's requirements from a generation and transmission cooperative might affect the financing ability of the generation and transmission cooperative. The Commission observes that, in general, if it permitted such contractual provisions to override the obligation to purchase from qualifying facilities, these contractual devices might be used to hinder the development of cogeneration and small power production. The Commission believes that the mandate of PURPA to encourage cogeneration and small power production requires that obligations to purchase under this provision supersede contractual restrictions on a utility's ability to obtain energy or capacity from a qualifying facility.

The Commission has, however, provided an alternate means by which any electric utility can meet this obligation. Under paragraph (d), if the qualifying facility consents, an all-requirements utility which would otherwise be obligated to purchase energy or capacity from the qualifying facility would be permitted to transmit the energy or capacity to its supplying utility. In most instances, this transaction would actually take the form of the displacement of energy or capacity that would have been provided under the all-requirements obligation. In this case, the supplying utility is deemed to have made the purchase and, as a result the all-requirements obligation is not affected.

In addition, if compliance with the purchase obligation would impose a special hardship on an all-requirements customer, the Commission may consider waiving such purchase obligation pursuant to the procedures set forth in § 292.403.

Transmission to Other Facilities

There are several circumstances in which a qualifying facility might desire that the electric utility with which it is interconnected not be the purchaser of the qualifying facility's energy and capacity, but would prefer instead that an electric utility with which the purchasing utility is interconnected make such a purchase. If, for example, the purchasing utility is a non-generating utility, its avoided costs will be the price of bulk purchased power ordinarily based on the average embedded cost of capacity and average energy cost on its supplying utility's system. As a result, the rate to the qualifying facility would be based on those average costs. If, however, the qualifying facility's output were purchased by the supplying utility, its output ordinarily will replace the highest cost energy on the supplying utility's system at that time, and its capacity might enable the supplying utility to avoid the addition of new capacity. Thus, the avoided costs of the supplying utility may be higher than the avoided cost of the non-generating utility.

This would not appear to be the case if the qualifying facility offers to supply capacity and energy in a situation in which the supplying utility is in an excess capacity situation. Since the supplying utility has excess capacity, its avoided costs would include only energy costs. On the other hand, if the avoided cost were based on the wholesale rate to the all-requirements utility, the avoided cost would include the demand charge included in the wholesale rate, which would usually reflect an allocation of a portion of the fixed charges associated with excess capacity.

Use of the unadjusted wholesale rate fails to take into account the effect of reduced revenue to the supplying utility, as a result of the substitute of the qualifying facility's output for energy previously supplied by the supplying utility. As the level of purchase by the all-requirements utility decreases, the supplying utility's fixed costs will have to be allocated over a smaller number of units of output. In effect, the loss in revenue to the supplying utility will cause the demand charges to the supplying utility's customers (including the all-requirements customers interconnected with the qualifying facility) to increase. Under the definition of "avoided costs" in this section, the purchasing utility must be in the same financial position it would have been had it not purchased the qualifying facility's output. As a result, rather than allocating its loss in revenue among all of its customers, in this situation the supplying utility should assign all of these losses to the all-requirements utility. That utility should, in turn, deduct these losses from its previously calculated avoided costs, and pay the qualifying facility accordingly.

Under these rules, certain small electric utilities are not required to provide system cost data, except upon request of a qualifying facility. If, with the consent of the qualifying facility, a small electric utility chooses to transmit energy from the qualifying facility to a second electric utility, the small utility can avoid the otherwise applicable requirements that it provide the system cost data for the qualifying facility and that it purchase the energy itself. However, the ability to transmit a purchase to another utility is not limited to these smaller systems; it applies to any utility.

Accordingly, paragraph (d) provides that a utility which receives energy or capacity from a qualifying facility may, with the consent of the qualifying facility, transmit such energy to another electric utility. However, if the first facility does not agree to transmit the purchased energy or capacity, it retains the purchase obligation. In addition, if the qualifying facility does not consent to transmission to another utility, the first utility retains the purchase obligation. Any electric utility to which such energy or capacity is delivered must purchase this energy under the obligations set forth in these rules as if the purchase were made directly from the qualifying facility.

One commenter stated that this provision could result in energy being transmitted to a utility which has little or no information regarding the reliability of the qualifying facility. The Commission believes that, prior to these transactions occurring, it will be in the interest of the qualifying facility to inform any utility to which energy or capacity is delivered, of the nature of those deliveries, so that such energy or capacity can be usefully integrated into that utility's power supply.

Several other commenters believed that this provision went beyond the authority of section 210 of PURPA—namely, that the Commission cannot require the first utility to wheel the power nor the second utility to buy the power. First, the Commission notes that this transmission can only occur with the consent of the utility to which energy or capacity from the qualifying facility is made available. Thus, no utility is forced to wheel. Secondly, section 210 does not limit the obligation to purchase to any particular utility; rather, it is a generally applicable requirement.

Paragraph (d) provides that charges for transmission are not a part of the rate which an electric utility to which energy is transmitted is obligated to pay the qualifying facility. In the case of electric utilities not subject to the jurisdiction of this Commission, these charges should be determined under applicable State law or regulation which may permit agreement between the qualifying facility and any electric utility which transmits energy or capacity with the consent of the qualifying facility. For utilities subject to the Commission's jurisdiction under Part II of the Federal Power Act, these charges will be determined pursuant to Part II.

The electric utility to which the electric energy is transmitted has the obligation to purchase the energy at a rate which reflects the costs that it can avoid as a result of making such a purchase. In cases in which electricity actually travels across the transmitting utility's system, the amount of energy delivered will be less than that transmitted, due to line losses. When this occurs, the rate for purchase can reflect these losses. In other cases, the energy supplied by the qualifying facility will displace energy that would have been supplied by the purchasing utility to the transmitting utility. In those cases, a unit of energy supplied from the qualifying facility may replace a greater amount of energy from the purchasing utility. In that case, the rate for purchase should be increased to reflect the net gain. These provisions are also set forth in paragraph (d).

§ *292.303(b) Obligation to sell to qualifying facilities.*

Paragraph (b) sets forth the statutory requirement of section 210(a) of PURPA that each electric utility offer to sell electric energy to qualifying facilities. The Commission observed in the Notice of Proposed Rulemaking that State law ordinarily sets out the obligation of an electric utility to provide service to customers located within its service area. In most instances, therefore, this rule will not impose additional obligations on electric utilities.

It is possible that a qualifying facility located outside the service area of an electric utility might require back-up, maintenance, or other types of power. The Commission believes that the instructions of section 210(a) of PURPA that it issue rules "as it determines necessary to encourage cogeneration and small power production * * *" mandate that it assure that such facilities are able to fulfill their needs for service.

However, the Commission also recognizes that State and local law limits the authority of some electric utilities to construct lines outside of their service area. Accordingly, the Commission requires electric utilities to serve any qualifying facility, and, subject to the restriction contained therein, to interconnect with any such facility as required in paragraph (c). However, an electric utility is only required to construct lines or other facilities to the extent authorized or required by State or local law. As a result, a qualifying facility outside the service area of a utility may be required to build its line into the service area of the utility.

§ *292.303(c) Obligation to interconnect.*

In the Notice of Proposed Rulemaking, the Commission used the interpretation set forth in the Staff Discussion Paper, that the obligation to interconnect with a qualifying facility is subsumed within the requirement of section 210(a) that electric utilities offer to sell electric energy to and purchase electric energy from qualifying facilities. The Commission observed that to hold otherwise would mean that Congress intended to require that qualifying facilities go through the complex procedures simply to gain interconnection, contrary to the mandate of section 210 of PURPA to encourage cogeneration and small power production.

During the comment period, this question was further explored, and it was suggested that the Commission has ample authority under the general mandate of section 210(a) of PURPA—namely, that it prescribe rules necessary to encourage cogeneration and small power production—to require interconnection.

While these interpretations received substantial support in the comments submitted, they were at the same time criticized on the theory that section 210(e)(3) of PURPA does not provide that a qualifying facility may be exempted from section 210 of the Federal Power Act (added by section 202 of PURPA and providing certain interconnection authority) and that this interconnection section specifically includes qualifying cogenerators and small power producers in its applicability. These commenters contended that since section 210 of the Federal Power Act deals explicitly with the subject of interconnections between qualifying facilities and electric utilities, no other section of that Act can be interpreted as also granting authority on that subject, as such an interpretation would render the express provision "surplusage".

With regard to these criticisms, the Commission observes that this argument might be tenable in the situation in which the section of the legislation which deals explicitly with the subject does not contain an express provision that it is *not* to be considered the exclusive authority on the subject. The Commission notes that section 212 of the Federal Power Act (as added by section 204 of PURPA) sets forth certain determinations that the Commission must make before it can issue an order under either section 210 or 211 of the Federal Power Act.

Section 212(e) states that no provision of section 210 of the Federal Power Act shall be treated "(1) as requiring any person to utilize the authority of such section 210 or 211 in lieu of any other authority of law, or (2) as limiting, impairing, or otherwise affecting any other authority of the Commission under any other provision of law." Thus, the Federal Power Act, as amended, expressly provides that the existence of authority under section 210 of the Federal Power Act to require interconnection is not to be interpreted as excluding any other interconnection authority available under any other law.

The Commission emphasizes that the limitation is not restricted to the Federal Power Act, but rather extends to include other authority of law, such as the authority contained in the Public Utility Regulatory Policies Act of 1978, of which section 210 is a part. Clearly, the existence of this provision refutes the contention that section 210 of the Federal Power Act represents the exclusive method by which interconnection can be obtained. As a result, the comment that the direction contained in section 210(e)(3) of PURPA that no qualifying facility can be exempted from section 210 or 212 of the Federal Power Act is not persuasive.

The Commission finds that to require qualifying facilities to go through the complex procedures set forth in section 210 of the Federal Power Act to gain interconnection would, in most circumstances, significantly frustrate the achievement of the benefits of this program. The Commission does not feel that the legal interpretation set forth in the Staff Discussion Paper and the Notice of Proposed Rulemaking is the exclusive theory by which it may require interconnections under this program without resort to sections 210 and 212 of the Federal Power Act. The interpretation brought out during the comment period—that section 210(a) of PURPA provides a general mandate for the Commission to prescribe rules necessary to encourage cogeneration and small power production—provides, in the Commission's view, sufficient authority to require interconnection. The Commission believes that a basic purpose of section 210 of PURPA is to provide a market for the electricity generated by small power producers and cogenerators. The Commission believes that accomplishment of this purpose would be greatly hindered if it were to require qualifying facilities to utilize section 210 of the Federal Power Act as the exclusive means of obtaining interconnection. It therefore concludes that such a restrictive interpretation of the law is not supportable.

Paragraph (c)(1) thus provides that an electric utility must make any interconnections with a qualifying facility which may be necessary to permit purchases from or sales to the qualifying facility. A State regulatory authority or nonregulated electric utility must enforce this requirement as part of its implementation of the Commission's rules.

In addition, several commenters contended that, if the obligation to interconnect is required under section 210(a) PURPA, the limitation provided in section 212 of the Federal Power Act would not be available. That limitation provides that an electric utility which complies with an interconnection order under section 210 of the Federal Power Act would not be subject to the jurisdiction of the Federal Energy Regulatory Commission for any purposes other than those specified in the interconnection order.

After consideration of this concern, the Commission has added paragraph (c)(2) to provide that no electric utility is required to interconnect with any qualifying facility, if, solely by reason of purchases or sales over the interconnection, the electric utility would become subject to regulation as a public utility under Part II of the Federal Power Act. This exception is provided because the Commission notes that, in balance, the encouragement of cogeneration and small power production would not be furthered if, by virtue of interconnection with a qualifying facility, a previously nonjurisdictional utility were reluctantly to become subject to federal utility regulation.

§ *292.303(e)* *Parallel operation.*

In the Notice of Proposed Rulemaking, the Commission provided that each electric utility must offer to operate in parallel with a qualifying facility, provided that the qualifying facility complies with standards established by the State regulatory authority or nonregulated electric utility with regard to the protection of system reliability pursuant to § 292.308. By operating in parallel, qualifying facilities are enabled to export automatically any electric energy which is not consumed by its own load. The comments submitted have not set forth any convincing reasons for changing the proposed rule. Paragraph (e) thus continues to require each electric utility to offer to operate in parallel with a qualifying facility.

§ *292.304 Rates for purchases.*

Section 210(b) of PURPA provides that in requiring any electric utility to purchase electric energy from a qualifying facility, the Commission must ensure that the rates for the purchase be just and reasonable to the electric consumers of the purchasing utility, in the public interest, and nondiscriminatory to qualifying facilities, but that they not exceed the incremental costs of alternative electric energy (the costs of energy to the utility, which, but for the purchase, the utility would generate itself or purchase from another source).

Relation to State Programs

The Commission has become aware that several States have enacted legislation requiring electric utilities in that State to purchase the electrical output of facilities which may be qualifying facilities under the Commission's rules at rates which may differ from the rates required under the Commission's rules implementing section 210 of PURPA.

This Commission has set the rate for purchases at a level which it believes appropriate to encourage cogeneration and small power production, as required by section 210 of PURPA. While the rules prescribed under section 210 of PURPA are subject to the statutory parameters, the States are free, under their own authority, to enact laws or regulations providing for rates which would result in even greater encouragement of these technologies. However, State laws or regulations which would provide rates lower than the federal standards would fail to provide the requisite encouragement of these technologies, and must yield to federal law.

If a State program were to provide that electric utilities must purchase power from certain types of facilities, among which are included "qualifying facilities," at a rate higher than that provided by these rules, a qualifying facility might seek to obtain the benefits of that State program. In such a case, however, the higher rates would be based on State authority to establish such rates, and not on the Commission's rules.

A facility which provides energy or capacity to a utility under State authority may nevertheless seek to obtain exemption from the Federal Power Act, the Public Utility Holding Company Act, and State regulation of electric utilities as available under section 210(e) of PURPA. The Commission notes that the States lack the authority to exempt a facility from the Federal Power Act or Public Utility Holding Company Act. The Commission finds no inconsistency in a facility's taking advantage of section 210 in order to obtain one of its benefits, while relying on other authority under which to buy from or sell to a utility.

§ *292.304(a) Rates for purchases.*

Paragraph (a) sets forth the statutory requirement that rates for purchases be just and reasonable to the electric consumers of the electric utility and in the public interest, and not discriminate against qualifying cogeneration and small power production facilities.

In the proposed rule, the Commission stated that there is a rebuttable presumption that the rate for purchases is acceptable if it reflects the avoided cost resulting from a purchase on the basis of system cost data set forth pursuant to § 292.302 (b) or (c). Many of the comments received stated that this section was ambiguous.[12] The Commission has therefore provided that the rate for purchases meets the statutory requirements if it equals avoided costs, and has eliminated the reference to the "rebuttable presumption".

Some comments recommended that, as a matter of policy, this section be revised to provide that a State regulatory authority or nonregulated utility has discretion to establish the relationship between the avoided cost and the rate for purchases. Other commenters contended that the Commission should specify that the rate for purchase must equal the avoided cost resulting from such a purchase. In addition, several suggested that the Commission adopt a "split-the-savings" approach.

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[12] The relationship between the utility system cost data and the rate for purchases is discussed under § 292.302 and § 292.304(b).

It is possible that developers of technologies which may be included as qualifying facilities may produce and make available power to electric facilities even though their cost of producing this power is greater than the utility's avoided costs. In most instances, however, purchases of energy or capacity from qualifying facilities will only occur when the cost to the qualifying cogenerator or small power producer of producing the energy or capacity is lower than the utility's avoided costs. Only if this is the case will payment by the utility of its avoided costs provide economic benefit for the cogenerator or small power producer.

When one electric utility can provide energy more cheaply than could another electric utility, the two utilities will often exchange power on a "split-the-savings" basis. In that type of transaction, the two utilities split the difference between the incremental costs incurred and the incremental costs that the purchasing utility would have incurred had it generated the power itself. Several commenters argued that rates for purchases from qualifying facilities should be based upon this same general principle. The effect of such a pricing mechanism would be to transfer to the utility's ratepayers a portion of the savings represented by the cost differential between the qualifying facility and the purchasing electric utility. Several utilities contend that by so allocating these savings, the Commission would provide an incentive for the electric utility to enter into purchase transactions with qualifying cogeneration and small power production facilities.

These commenters also noted that they had previously engaged in purchases from facilities which might become qualifying facilities under the Commission's rules, and they had paid prices for these purchases based on a "split-the-savings" methodology. These commenters observed that if the Commission's rules now require the payment of full avoided cost for these types of purchases, the purchased power expenses of the electric utility would increase.

Moreover, several utilities commented that, for the forseeable future, they are inextricably tied to the use of oil to produce electricity. They contend that unless they are permitted to purchase energy and capacity from qualifying facilities at a rate somewhere between the qualifying facilities' costs and their own costs, they and their ratepayers will be subject to the continually increasing world price of oil.

Commenters opposing this allocation of savings to parties other than the qualifying facility noted that this section of PURPA is intended to encourage the development of cogeneration and small power production. They noted that in providing for this encouragement, the Commission may not set rates for purchases at a level which exceeds the incremental cost of alternative energy. Therefore, they observed that, under the full avoided cost standard, the utilities' customers are kept whole, and pay the same rates as they would have paid had the utility not purchased energy and capacity from the qualifying facility.

Although use of the full avoided cost standard will not produce any rate savings to the utility's customers, several commenters stated that these ratepayers and the nation as a whole will benefit from the decreased reliance of scarce fossil fuels, such as oil and gas, and the more efficient use of energy.

The Commission notes that, in most instances, if part of the savings from cogeneration and small power production were allocated among the utilities' ratepayers, any rate reductions will be insignificant for any individual customer. On the other hand, if these savings are allocated to the relatively small class of qualifying cogenerators and small power producers, they may provide a significant incentive for a higher growth rate of these technologies.

Another concern with the use of a split-the-savings rate for purchases is that it would require a determination of the costs of production of the qualifying facility. A major portion of this legislation is intended to exempt qualifying facilities from the cost-of-service regulation by which electric utilities traditionally have been regulated. The Conference Report noted that:

> It is not the intention of the Conferees that cogenerators and small power producers become subject . . . to the type of examination that is traditionally given to electric utility rate applications to determine what is the just and reasonable rate that they should receive for their electric power.[13]

Thus, section 210(e) of PURPA provides that the Commission shall exempt qualifying facilities from the Public Utility Holding Company Act, from the Federal Power Act and from State law and regulation respecting utility rates or financial organization, to the extent that the Commission determines that such exemption is necessary to encourage cogeneration or small power production.

Several commenters have contended that a determination of the qualifying facility's costs can be made without the detail required by cost-of-service regulation. However, the Commission believes that the basis for the determination of rates for purchases should be the utility's avoided costs and should not vary on the basis of the costs of the particular qualifying facility.

Several commenters recommended that rather than using a split-the-savings approach, the Commission should set rates for purchases at a fixed percentage of avoided costs. The Commission notes that, in most situations, a qualifying cogenerator or small power producer will only produce energy if its marginal cost of production is less than the price he receives for its output. If some fixed percentage is used, a qualifying facility may cease to produce additional units of energy when its costs exceed the price to be paid by the utility. If this occurs, the utility will be forced to operate generating units which either are less efficient than those which would have been used by the qualifying facility, or which consume fossil fuel rather than the alternative fuel which would have been consumed by the qualifying facility had the price been set at full avoided costs.

§ 292.304(b) Relationship to avoided costs.

"New Capacity"[14]

The proposed rule differentiated between "old" and "new" production in connection with simultaneous purchases and sales. The proposed rule required an electric utility to purchase at its avoided cost the total output of a facility, construction of which was commenced after the date of issuance of these rules, even if the utility simultaneously sells energy to the facility at its retail rate. The effect of this proposed rule was to separate the production aspect of a qualifying facility from its consumption function. Under this approach, the electrical output of a facility is viewed independently of its electrical needs. Thus, if a cogeneration facility produces five megawatts, and consumes three megawatts, it is treated the same as another qualifying facility that produces five megawatts, and that is located next to a factory that uses three megawatts.

The Commission continues to believe that permitting simultaneous purchase and sale is necessary and appropriate to encourage cogeneration and small power production. The limitation contained in the proposed rule was intended to prevent a cogenerator or small power producer, which had found it economical to produce power for its own consumption prior to the issuance of these rules, from receiving the economic rent that might result from the purchase of its entire output at a utility's full avoided cost after that date without new investment on the part of the qualifying facility.

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[13] Conference Report on H.R. 4018, Public Utility Regulatory Policies Act of 1978, H. Rep. No. 1750, 97 95th Cong., 2d. Sess. (1978).

The same reasoning applies to any facility which was in existence prior to the enactment of PURPA, whether or not it seeks to purchase and sell simultaneously. That construction of the facility was commenced prior to that date may indicate that appropriate economic returns were available without the further incentives provided by section 210.

The Commission is aware that in some instances, if a previously existing qualifying facility were not permitted to receive full avoided costs for its entire output, it would no longer have sufficient incentive to continue to produce electric power. The cost of production may have risen so as to render the previous rate insufficient to cover the costs of production, or permit an appropriate return.

Thus, with regard to facilities, construction of which commenced on or after the date of enactment of PURPA (November 9, 1978), the Commission has determined it appropriate to provide that rates for purchases shall equal full avoided costs. For facilities, construction of which commenced before the enactment of PURPA, the Commission will permit the State regulatory authorities and nonregulated electric utilities to establish rates for purchases at full avoided costs, or at a lower rate, if the State regulatory authority or nonregulated electric utility determines that the lower rate will provide sufficient encouragement of cogeneration and small power production. Thus, if a previously existing facility shows that it requires rates for purchases based on full avoided costs to remain viable, or to increase its output, the State regulatory authority or nonregulated electric utility is required to establish such rates. This distinction is intended to reflect the need for further incentives and the reasonable expectations of persons investing in cogeneration or small power production facilities prior to or subsequent to the enactment of this law.

Paragraph (b)(1) defines "new capacity" as any purchase of capacity from a qualifying facility, construction of which was commenced on or after November 9, 1978. Subparagraph (2) provides that for new capacity, utilities must pay a rate which equals their avoided cost.

A utility must therefore purchase all of the output from a qualifying facility. However, as explained above, for any portion of that output which is not "new capacity," the State regulatory authority or nonregulated electric utility, as provided in paragraph (b)(3), may provide for a lower rate, if it determines that the lower rate will provide sufficient incentive for cogeneration.

Paragraph (b)(4) requires electric utilities to pay full avoided costs for purchases from new capacity made available from a qualifying facility, regardless of whether the electric utility is simultaneously making sales to the qualifying facility.

§ 292.304(c) Standard rates for purchases.

The Notice of Proposed Rulemaking required electric utilities on request of a qualifying facility to establish a tariff or other method for establishing rates for purchase from qualifying facilities of 10 kw or less. Upon consideration of the comments received, the Commission has determined that the concept of requiring a standard rate for purchases should be retained. Several comments stated that this requirement could similarly be applied to facilities of up to 100 kw or less.

The Commission is aware that the supply characteristics of a particular facility may vary in value from the average rates set forth in the utility's standard rate required by this paragraph. If the Commission were to require individualized rates, however, the transaction costs associated with administration of the program would likely render the program uneconomic for this size of qualifying facility. As a result, the Commission will require that standardized tariffs be implemented for facilities of 100 kw or less.

In addition, some commenters pointed out that standard tariffs can be used on a technology specific basis, to reflect the supply characteristics of the particular technology. Some commenters also observed that the proposed rule did not require that standard rates for purchases from these small facilities be based on the purchasing utility's avoided cost. This omission might have permitted a utility to pay less than that rate for purchases.

The Commission has accordingly revised paragraph (c) to require each State regulatory authority or nonregulated electric utility to cause to be put into effect standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less. The revised rule requires that standard rates for purchases equal the purchasing utility's avoided cost pursuant to paragraphs (a), (b), and (e).

Several commenters noted that standard rates for purchases can also be usefully applied to larger facilities. The Commission believes that the establishment of standard rates for purchases can significantly encourage cogeneration and small power production, provided that these standard rates accurately reflect the costs that the utility can avoid as a result of such purchases. Accordingly, the Commission has added subparagraph (2) which permits, but does not require, State regulatory authorities and nonregulated electric utilities to put into effect a standard rate for purchases from qualifying facilities with a design capacity greater than 100 kilowatts. These rates must equal avoided cost pursuant to paragraphs (a), (b), and (e).

Many commenters at the Commission's public hearings and in written comments recommended that the Commission should require the establishment of "net energy billing" for small qualifying facilities. Under this billing method, the output from a qualifying facility reverses the electric meter used to measure sales from the electric utility to the qualifying facility. The Commission believes that this billing method may be an appropriate way of approximating avoided cost in some circumstances, but does not believe that this is the only practical or appropriate method to establish rates for small qualifying facilities. The Commission observes that net energy billing is likely to be appropriate when the retail rates are marginal cost-based, time-of-day rates. Accordingly, the Commission will leave to the State regulatory authorities and the nonregulated electric utilities the determination as to whether to institute net energy billing.

Paragraph (c)(3)(i) provides that standard rates for purchase should take into account the factors set forth in paragraph (e). These factors relate to the quality of power from the qualifying facility, and its ability to fit into the purchasing utility's generating mix.

Paragraph (e)(vi) is of particular significance for facilities of 100 kW or less. This paragraph provides that rates for purchase shall take into account "the individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system . . .". Several commenters presented persuasive evidence showing that an effective amount of capacity may be provided by dispersed small systems, even in the case where delivery of energy from any particular facility is stochastic. Similarly, qualifying facilities may be able to enter into operating agreements with each other by which they are able to increase the assured availability of capacity to the utility by coordinating scheduled maintenance and providing mutual back-up service. To the extent that this aggregate capacity value can be reasonably estimated, it must be reflected in standard rates for purchases.

Several commenters observed that the patterns of availability of particular energy sources can and should be reflected in standard rates. An example of this phenomenon is the availability of wind and photovoltaic energy on a summer peaking system. If it can be shown that system peak occurs when there is bright sun and no wind, rates for purchase could provide a higher capacity payment for photovoltaic cells than for wind energy conversion systems. For systems peaking on dark windy days, the reverse might be true. Subparagraph (3)(ii) thus provides that standard rates for purchases may differentiate among qualifying facilities on the basis of the supply characteristics of the particular technology.

§§ *292.304 (b)(5) and (d)* *Legally enforceable obligations.*

Paragraphs (b)(5) and (d) are intended to reconcile the requirement that the rates for purchases equal the utilities' avoided cost with the need for qualifying facilities to be able to enter into contractual commitments based, by necessity, on estimates of future avoided costs. Some of the comments received regarding this section stated that, if the avoided cost of energy at the time it is supplied is less than the price provided in the contract or obligation, the purchasing utility would be required to pay a rate for purchases that would subsidize the qualifying facility at the expense of the utility's other ratepayers. The Commission recognizes this possibility, but is cognizant that in other cases, the required rate will turn out to be lower than the avoided cost at the time of purchase. The Commission does not believe that the reference in the statute to the incremental cost of alternative energy was intended to require a minute-by-minute evaluation of costs which would be checked against rates established in long term contracts between qualifying facilities and electric utilities.

Many commenters have stressed the need for certainty with regard to return on investment in new technologies. The Commission agrees with these latter arguments, and believes that, in the long run, "overestimations" and "underestimations" of avoided costs will balance out.

Paragraph (b)(5) addresses the situation in which a qualifying facility has entered into a contract with an electric utility, or where the qualifying facility has agreed to obligate itself to deliver at a future date energy and capacity to the electric utility. The import of this section is to ensure that a qualifying facility which has obtained the certainty of an arrangement is not deprived of the benefits of its commitment as a result of changed circumstances. This provision can also work to preserve the bargain entered into by the electric utility; should the actual avoided cost be higher than those contracted for, the electric utility is nevertheless entitled to retain the benefit of its contracted for, or otherwise legally enforceable, lower price for purchases from the qualifying facility. This subparagraph will thus ensure the certainty of rates for purchases from a qualifying facility which enters into a commitment to deliver energy or capacity to a utility.

Paragraph (d)(1) provides that a qualifying facility may provide energy or capacity on an "as available" basis, i.e., without legal obligation. The proposed rule provided that rates for such purchases should be based on "actual" avoided costs. Many comments noted that basing rates for purchases in such cases on the utility's "actual avoided costs" is misleading and could require retroactive ratemaking. In light of these comments, the Commission has revised the rule to provide that the rates for purchases are to be based on the purchasing utility's avoided costs estimated at the time of delivery.[14]

Paragraph (d)(2) permits a qualifying facility to enter into a contract or other legally enforceable obligation to provide energy or capacity over a specified term. Use of the term "legally enforceable obligation" is intended to prevent a utility from circumventing the requirement that provides capacity credit for an eligible qualifying facility merely by refusing to enter into a contract with the qualifying facility.

Many commenters noted the same problems for establishing rates for purchases under subparagraph (2) as in subparagraph (1). The Commission intends that rates for purchases be based, at the option of the qualifying facility, on either the avoided costs at the time of delivery or the avoided costs calculated at the time the obligation is incurred. This change enables a qualifying facility to establish a fixed contract price for its energy and capacity at the outset of its obligation or to receive the avoided costs determined at the time of delivery.

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[14] In addition to the avoided costs of energy, these costs must include the prorated share of the aggregate capacity value of such facilities.

A facility which enters into a long term contract to provide energy or capacity to a utility may wish to receive a greater percentage of the total purchase price during the beginning of the obligation. For example, a level payment schedule from the utility to the qualifying facility may be used to match more closely the schedule of debt service of the facility. So long as the total payment over the duration of the contract term does not exceed the estimated avoided costs, nothing in these rules would prohibit a State regulatory authority or non-regulated electric utility from approving such an arrangement.

§ 292.304(c) Factors affecting rates for purchases.

Capacity Value

An issue basic to this paragraph is the question of recognition of the capacity value of qualifying facilities.

In the proposed rule, the Commission adopted the argument set forth in the Staff Discussion Paper that the proper interpretation of section 210(b) of PURPA requires that the rates for purchases include recognition of the capacity value provided by qualifying cogeneration and small power production facilities. The Commission noted that language used in section 210 of PURPA and the Conference Report as well as in the Federal Power Act supports this proposition.

In the proposed rule, the Commission cited the final paragraph of the Conference Report with regard to section 210 of PURPA:

> The conferees expect that the Commission, in judging whether the electric power supplied by the cogenerator or small power producer will replace future power which the utility would otherwise have to generate itself either through existing capacity or additions to capacity or purchase from other sources, will take into account the reliability of the power supplied by the cogenerator or small power producer by reason of any legally enforceable obligation of such cogenerator or small power producer to supply firm power to the utility.[15]

In addition to that citation, the Commission notes that the Conference Report states that:

> In interpreting the term "incremental costs of alternative energy", the conferees expect that the Commission and the States may look beyond the costs of alternative sources which are instantaneously available to the utility.[16]

Several commenters contended that, since section 210(a)(2) of PURPA provides that electric utilities must "purchase electric energy" from qualifying facilities, the rate for such purchases should not include payments for capacity. The Commission observes that the statutory language used in the Federal Power Act uses the term "electric energy" to describe the rates for sales for resale in interstate commerce. Demand or capacity payments are a traditional part of such rates. The term "electric energy" is used throughout the Act to refer both to electric energy and capacity. The Commission does not find any evidence that the term "electric energy" in section 210 of PURPA was intended to refer only to fuel and operating and maintenance expenses, instead of all of the costs associated with the provision of electric service.

In addition, the Commission notes that to interpret this phrase to include only energy would lead to the conclusion that the rates for sales *to* qualifying facilities could only include the energy component of the rate since section 210 also refers to "electric energy" with regard to such sales. It is the Commission's belief that this was not the intended result. This provides an additional reason to interpret the phrase "electric energy" to include both energy and capacity.

In implementing this statutory standard, it is helpful to review industry practice respecting sales between utilities. Sales of electric power are ordinarily classified as either firm sales, where the seller provides power at the customer's request, or non-firm power sales, where the seller and not the buyer makes the decision whether or not power is to be available. Rates for firm power purchases include payments for the cost of fuel and operating expenses, and also for the fixed costs associated with the construction of generating units needed to provide power at the purchaser's discretion. The degree of certainty of deliverability required to constitute "firm power" can ordinarily be obtained only if a utility has several generating units and adequate reserve capacity. The capacity payment, or demand charge, will reflect the cost of the utility's generating units.

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[15] Conference Report on H.R. 4018, Public Utility Regulatory Policies Act of 1978, H. Rep. No. 1750, 99, 95th Cong., 2d. Sess. (1978).

[16] *Id.*, pp. 98-9.

In contrast, the ability to provide electric power at the selling utility's discretion imposes no requirement that the seller construct or reserve capacity. In order to provide power to customers at the seller's discretion, the selling utility need only charge for the cost of operating its generating units and administration. These costs, called "energy" costs, ordinarily are the ones associated with non-firm sales of power.

Purchases of power from qualifying facilities will fall somewhere on the continuum between these two types of electric service. Thus, for example, wind machines that furnish power only when wind velocity exceeds twelve miles per hour may be so uncertain in availability of output that they would only permit a utility to avoid generating an equivalent amount of energy. In that situation, the utility must continue to provide capacity that is available to meet the needs of its customers. Since there are no avoided capacity costs, rates for such sporadic purchases should thus be based on the utility system's avoided incremental cost of energy. On the other hand, testimony at the Commission's public hearings indicated that effective amounts of firm capacity exist for dispersed wind systems, even though each machine, considered separately, could not provide capacity value. The aggregate capacity value of such facilities must be considered in the calculation of rates for purchases, and the payment distributed to the class providing the capacity.

Some technologies, such as photovoltaic cells, although subject to some uncertainty in power output, have the general advantage of providing their maximum power coincident with the system peak when used on a summer peaking system. The value of such power is greater to the utility than power delivered during off-peak periods. Since the need for capacity is based, in part, on system peaks, the qualifying facility's coincidence with the system peak should be reflected in the allowance of some capacity value and an energy component that reflects the avoided energy costs at the time of the peak.

A facility burning municipal waste or biomass may be able to operate more predictably and reliably than solar or wind systems. It can schedule its outages during times when demand on the utility's system is low. If such a unit demonstrates a degree of reliability that would permit the utility to defer or avoid construction of a generating unit or the purchase of firm power from another utility, then the rate for such a purchase should be based on the avoidance of both energy and capacity costs.

In order to defer or cancel the construction of new generating units, a utility must obtain a commitment from a qualifying facility that provides contractual or other legally enforceable assurances that capacity from alternative sources will be available sufficiently ahead of the date on which the utility would otherwise have to commit itself to the construction or purchase of new capacity. If a qualifying facility provides such assurances, it is entitled to receive rates based on the capacity costs that the utility can avoid as a result of its obtaining capacity from the qualifying facility.

Other comments with regard to the requirement to include capacity payments in avoided costs generally track those set forth in the Staff Discussion Paper and the proposed rule. The thrust of these comments is that, in order to receive credit for capacity and to comply with the requirement that rates for purchases not exceed the incremental cost of alternative energy, capacity payments can only be required when the availability of capacity from a qualifying facility or facilities actually permits the purchasing utility to reduce its need to provide capacity by deferring the construction of new plant or commitments to firm power purchase contracts. In the proposed rule, the

Commission stated that if a qualifying facility offers energy of sufficient reliability and with sufficient legally enforceable guarantees of deliverability to permit the purchasing electric utility to avoid the need to construct a generating plant, to enable it to build a smaller, less expensive plant, or to purchase less firm power from another utility than it would otherwise have purchased, then the rates for purchases from the qualifying facility must include the avoided capacity and energy costs. As indicated by the preceding discussion, the Commission continues to believe that these principles are valid and appropriate, and that they properly fulfill the mandate of the statute.

The Commission also continues to believe, as stated in the proposed rule, that this rulemaking represents an effort to evolve concepts in a newly developing area within certain statutory constraints. The Commission recognizes that the translation of the principle of avoided capacity costs from theory into practice is an extremely difficult exercise, and is one which, by definition, is based on estimation and forecasting of future occurrences. Accordingly, the Commission supports the recommendation made in the Staff Discussion Paper that it should leave to the States and nonregulated utilities "flexibility for experimentation and accommodation of special circumstances" with regard to implementation of rates for purchases. Therefore, to the extent that a method of calculating the value of capacity from qualifying facilities reasonably accounts for the utility's avoided costs, and does not fail to provide the required encouragement of cogeneration and small power production, it will be considered as satisfactorily implementing the Commission's rules.

§ 292.304(e) Factors affecting rates for purchases.

As noted previously, several commenters observed that the utility system cost data required under § 292.302 cannot be directly applied to rates for purchase. The Commission acknowledges this point and, as discussed previously, has provided that these data are to be used as a starting point for the calculation of an appropriate rate for purchases equal to the utility's avoided cost. Accordingly, the Commission has removed the reference to the utility system cost data from the definition of rates for purchases, and has inserted the reference to these data in paragraph (e), as one factor to be considered in calculating rates for purchases. Subparagraph (1) states that these data shall, to the extent practicable, be taken into account in the calculation of a rate for purchases.

Subparagraph (2) deals with the availability of capacity from a qualifying facility during system daily and seasonal peak periods. If a qualifying facility can provide energy to a utility during peak periods when the electric utility is running its most expensive generating units, this energy has a higher value to the utility than energy supplied during off-peak periods, during which only units with lower running costs are operating.

The preamble to the proposed rule provided that, to the extent that metering equipment is available, the State regulatory authority or nonregulated electric utility should take into account the time or season in which the purchase from the qualifying facility occurs. Several commenters interpreted this statement as implying that, by refusing to install metering equipment, an electric utility could avoid the obligation to consider the time at which purchases occur. This is not the intent of this provision. Clearly, the more precisely the time of purchase is recorded the more exact the calculation of the avoided costs, and thus the rate for purchases, can be. Rather than specifying that exact time-of-day or seasonal rates for purchases are required, however, the Commission believes that the selection of a methodology is best left to the State regulatory authorities and nonregulated electric utilities charged with the implementation of these provisions.

Clauses (i) through (v) concern various aspects of the reliability of a qualifying facility. When an electric utility provides power from its own generating units or from those of another electric utility, it normally controls the production of such power from a central location. The ability to so control power production enhances a utility's ability to respond to changes in demand, and thereby enhances the value of that power to the utility. A qualifying facility may be able to enter into an arrangement with the utility which gives the utility the advantage of dispatching the facility. By so doing, it increases its value to the utility. Conversely, if a utility cannot dispatch a qualifying facility, that facility may be of less value to the utility.

Clause (ii) refers to the expected or demonstrated reliability of a qualifying facility. A utility cannot avoid the construction or purchase of capacity if it is likely that the qualifying facility which would claim to replace such capacity may go out of service during the period when the utility needs its power to meet system demand. Based on the estimated or demonstrated reliability of a qualifying facility, the rate for purchases from a qualifying facility should be adjusted to reflect its value to the utility.

Clause (iii) refers to the length of time during which the qualifying facility has contractually or otherwise guaranteed that it will supply energy or capacity to the electric utility. A utility-owned generating unit normally will supply power for the life of the plant, or until it is replaced by more efficient capacity. In contrast, a cogeneration or small power production unit might cease to produce power as a result of changes in the industry or in the industrial processes utilized. Accordingly, the value of the service from the qualifying facility to the electric utility may be affected by the degree to which the qualifying facility ensures by contract or other legally enforceable obligation that it will continue to provide power. Included in this determination, among other factors, are the term of the commitment, the requirement for notice prior to termination of the commitment, and any penalty provisions for breach of the obligation.

In order to provide capacity value to an electric utility a qualifying facility need not necessarily agree to provide power for the life of the plant. A utility's generation expansion plans often include purchases of firm power from other utilities in years immediately preceding the addition of a major generation unit. If a qualifying facility contracts to deliver power, for example, for a one year period, it may enable the purchasing utility to avoid entering into a bulk power purchase arrangement with another utility. The rate for such a purchase should thus be based on the price at which such power is purchased, or can be expected to be purchased, based upon bona fide offers from another utility.

Clause (iv) addresses periods during which a qualifying facility is unable to provide power. Electric utilities schedule maintenance outages for their own generating units during periods when demand is low. If a qualifying facility can similarily schedule its maintenance outages during periods of low demand, or during periods in which a utility's own capacity will be adequate to handle existing demand, it will enable the utility to avoid the expenses associated with providing an equivalent amount of capacity. These savings should be reflected in the rate for purchases.

Clause (v) refers to a qualifying facility's ability and willingness to provide capacity and energy during system emergencies. Section 292.307 of these regulations concerns the provision of electric service during system emergencies. It provides that, to the extent that a qualifying facility is willing to forego its own use of energy during system emergencies and provide power to a utility's system, the rate for purchases from the qualifying facility should reflect the value of that service. Small power production and cogeneration facilities could provide significant back-up capability to electric systems during emergencies. One benefit of the encouragement of interconnected cogeneration and small power production may be to increase overall system reliability during such emergency conditions. Any such benefit should be reflected in the rate for purchases from such qualifying facilities.

Another related factor which affects the capacity value of a qualifying facility is its ability to separate its load from its generation during system emergencies. During such emergencies an electric utility may institute load shedding procedures which may, among other things, require that industrial customers or other large loads stop receiving power. As a result, to provide optimal benefit to a utility in an emergency situation, a qualifying facility might be required to continue operation as a generating plant, while simultaneously ceasing operation as a load on the utility's system. To the extent that a facility is unable to separate its load from its generation, its value to the purchasing utility decreases during system emergencies. To reflect such a possibility, clause (v) provides that the purchasing utility may consider the qualifying facility's ability to separate its load from its generation during system emergencies in determining the value of the qualifying facility to the electric utility.

Clause (vi) refers to the aggregate capability of capacity from qualifying facilities to displace planned utility capacity. In some instances, the small amounts of capacity provided from qualifying facilities taken individually might not enable a purchasing utility to defer or avoid scheduled capacity additions. The aggregate capability of such purchases may, however, be sufficient to permit the deferral or avoidance of a capacity addition. Moreover, while an individual qualifying facility may not provide the equivalent of firm power to the electric utility, the diversity of these facilities may collectively comprise the equivalent of capacity.

Clause (vii) refers to the fact that the lead time associated with the addition of capacity from qualifying facilities may be less than the lead time that would have been required if the purchasing utility had constructed its own generating unit. Such reduced lead time might produce savings in the utility's total power production costs, by permitting utilities to avoid the "lumpiness," and temporary excess capacity associated therewith, which normally occur when utilities bring on line large generating units. In addition, reduced lead time provides the utility with greater flexibility with which it can accommodate changes in forecasts of peak demand.

Subparagraph (3) concerns the relationship of energy or capacity from a qualifying facility to the purchasing electric utility's need for such energy or capacity. If an electric utility has sufficient capacity to meet its demand, and is not planning to add any new capacity to its system, then the availability of capacity from qualifying facilities will not immediately enable the utility to avoid any capacity costs. However, an electric utility system with excess capacity may nevertheless plan to add new, more efficient capacity to its system. If purchases from qualifying facilities enable a utility to defer or avoid these new planned capacity additions, the rate for such purchases should reflect the avoided costs of these additions. However, as noted by several commenters, the deferral or avoidance of such a unit will also prevent the substitution of the lower energy costs that would have accompanied the new capacity. As a result, the price for the purchase of energy and capacity should reflect these lower avoided energy costs that the utility would have incurred had the new capacity been added.

This is not to say that electric utilities which have excess capacity need not make purchases from qualifying facilities; qualifying facilities may obtain payment based on the avoided energy costs on a purchasing utility's system. Many utility systems with excess capacity have intermediate or peaking units which use high-cost fossil fuel. As a result, during peak hours, the energy costs on the systems are high, and thus the rate to a qualifying utility from which the electric utility purchases energy should similarly be high.

Subparagraph (4) addresses the costs or savings resulting from line losses. An appropriate rate for purchases from a qualifying facility should reflect the cost savings actually accruing to the electric utility. If energy produced from a qualifying facility undergoes line losses such that the delivered power is not equivalent to the power that would have been delivered from the source of power it replaces, then the qualifying facility should not be reimbursed for the difference in losses. If the load served by the qualifying facility is closer to the qualifying facility than it is to the utility, it is possible that there may be net savings resulting from reduced line losses. In such cases, the rates should be adjusted upwards.

§ *292.303(f)* *Periods during which purchase are not required.*

The proposed rule provided that an electric utility will not be required to purchase energy and capacity from qualifying facilities during periods in which such purchases will result in net increased operating costs to the electric utility. This section was intended to deal with a certain condition which can occur during light loading periods. If a utility operating only base load units during these periods were forced to cut back output from the units in order to accommodate purchases from qualifying facilities, these base load units might not be able to increase their output level rapidly when the system demand later increased. As a result, the utility would be required to utilize less efficient, higher cost units with faster start-up to meet the demand that would have been supplied by the less expensive base load unit had it been permitted to operate at a constant output.

The result of such a transaction would be that rather than avoiding costs as a result of the purchase from a qualifying facility, the purchasing electric utility would incur greater costs than it would have had it not purchased energy or capacity from the qualifying facility. A strict application of the avoided cost principle set forth in this section would assess these additional costs as negative avoided costs which must be reimbursed by the qualifying facility. In order to avoid the anomalous result of forcing a qualifying utility to pay an electric utility for purchasing its output, the Commission proposed that an electric utility be required to identify periods during which this situation would occur, so that the qualifying facility could cease delivery of electricity during those periods.

Many of the comments received reflected a suspicion that electric utilities would abuse this paragraph to circumvent their obligation to purchase from qualifying facilities. In order to minimize that possibility, the Commission has revised this paragraph to provide that any electric utility which seeks to cease purchasing from qualifying facilities must notify each affected qualifying facility prior to the occurrence of such a period, in time for the qualifying facility to cease delivery of energy or capacity to the electric utility. This notification can be accomplished in any reasonable manner determined by the State regulatory authority. Any claim by an electric utility that such a light loading period will occur or has occurred is subject to such verification by its State regulatory authority as the State authority determines necessary or appropriate either before or after its occurrence. Moreover, any electric utility which fails to provide adequate notice or which incorrectly identifies such a period will be required to reimburse the qualifying facility for energy or capacity supplied as if such a light loading period had not occurred.

The section has also been modified to clarify that such periods must be due to operational circumstances.

The Commission does not intend that this paragraph override contractual or other legally enforceable obligations incurred by the electric utility to purchase from a qualifying facility. In such arrangements, the established rate is based on the recognition that the value of the purchase will vary with the changes in the utility's operating costs. These variations ordinarily are taken into account, and the resulting rate represents the average value of the purchase over the duration of the obligation. The occurrence of such periods may similarly be taken into account in determining rates for purchases.

Tax Issues

The Conference Report states that:

> * * * the examination of the level of rates which should apply to the purchase by the utility of the cogenerator's or the small power producer's power should not be burdened by the same examination as are utility rate

applications to determine what is the just and reasonable rate that they should receive for their electric power.[17]

The Commission notes that section 301(b)(2) of the Energy Tax Act of 1978[18] makes certain energy property eligible for increased business investment tax credit. Some of this property is commonly used in cogeneration and small power production. However, section 301(b)(2)(B) excludes from such eligibility property "which is public utility property (within the meaning of section 46(f)(5) of the Internal Revenue Code of 1954)."[19] As a result, if the property of a qualifying facility which was otherwise eligible for the credit were to be classified as public utility property under section 46(f)(5) of the Internal Revenue Code, it would not be eligible for the increased investment tax credit.

The Commission notes that the Treasury Department's regulations provide that the definition of "public utility property" does not include property used in the business of the furnishing or sale of electric energy if the rates are not subject to regulation that fixes a rate of return on investment.[20] On this basis, the Commission believes that property of a qualifying facility that would otherwise be eligible for the energy tax credit would not be excluded from that eligibility under the public utility property exclusion.

First, this Commission is exempting property of qualifying facilities from regulation under Part II of the Federal Power Act, and from similar State and local laws and regulatory programs. Secondly, the Commission observes that the rates a qualifying facility will receive for sales of power to utilities are *not* based on a regulatory scheme which fixes a rate of return on investment of the qualifying facility.

As a result, the Commission believes that energy property of qualifying facilities should not be barred from eligibility for the tax credit by reason of the public utility property exclusion. The Commission wishes to express its opinion on this matter in an effort to further encourage cogeneration and small power production by means of this rulemaking process.

§ 292.305 Rates for sales.

Section 210(c) of PURPA provides that the rules requiring utilities to sell electric energy to qualifying facilities shall ensure that the rates for such sales are just and reasonable, in the public interest, and nondiscriminatory with respect to qualifying cogenerators or small power producers. This section contemplates formulation of rates on the basis of traditional ratemaking (*i.e.*, cost-of-service) concepts.

Paragraph (a) expresses the statutory requirement that such rates be just and reasonable and in the public interest. Paragraph (a) also provides that rates for sales from electric utilities to qualifying facilities not be discriminatory against such facilities in comparison to rates to other customers served by the electric utility.

A qualifying facility is entitled to purchase back-up or standby power at a nondiscriminatory rate which reflects the probability that the qualifying facility will or will not contribute to the need for and the use of utility capacity. Thus, where the utility must reserve capacity to provide service to a qualifying facility, the costs associated with that reservation are properly recoverable from the qualifying facility, if the utility would similarly assess these costs to non-generating customers.

In the proposed rule, paragraph (b) required electric utilities to provide energy and capacity and other services to any qualifying facility at a rate at least as favorable as would be provided to a customer who does not have his own generation. The comments received concerning this paragraph noted that this provision might be interpreted as requiring an electric utility to provide service to a qualifying facility at its most favorable rate, even if the qualifying facility would not be eligible for such a rate if it did not have its own generation. It is not the Commission's intention that, for example, an industrial cogenerator receive service at a rate applicable to residential customers; rather, such a customer should be charged at a rate applicable to a non-generating industrial customer unless the electric utility shows that a different rate is justified on the basis of sufficient load or other cost-related data. Accordingly, this section now provides that for qualifying facilities which do not simultaneously sell and purchase from the electric utility, the rate for sales shall be the rate that would be charged to the class to which the qualifying facility would be assigned if it did not have its own generation.

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[17] Conference Report on H.R. 4018, Public Utility Regulatory Policies Act of 1978, H. Rep. No. 1750, 98, 95th Cong., 2d Sess. (1978).

[18] Pub. L. No. 95-618, 26 U.S.C. §§ 46, 48, November 9, 1978.

[19] 26 U.S.C. § 46(e)(3)(b).

[20] Treasury Reg. § 146-3(g)(2), T.D. 7602 (March 23, 1979).

Subparagraph (2) provides that if, on the basis of accurate data and consistent system-wide costing principles, the utility demonstrates that the rate that would be charged to a comparable customer without its own generation is not appropriate, the utility may base its rates for sales upon those data and principles. The utility may only charge such rates on a nondiscriminatory basis, however, so that a cogenerator will not be singled out to lose any interclass or intraclass subsidies to which it might have been entitled had it not generated part of its electric energy needs itself.

In situations where a qualifying facility simultaneously sells its output to an electric utility and purchases its requirements from that electric utility, as a bookkeeping matter, the facility's electrical output will not serve its own load, but rather will be supplied to the grid. As a result, the facility's electric load is likely to have the same characteristics as the load of other non-generating customers of the utility. If the utility does not provide data showing otherwise, the appropriate rate for sales to such a facility is the rate that would be charged to a comparable customer without its own generation.

Paragraph (b)(2) of the rule sets forth certain types of service which electric utilities are required to provide qualifying facilities upon request of the facility. These types of service are supplementary power, back-up power, interruptible power and maintenance power. In response to comments, these terms are defined in the text of the rules, as well as in this preamble.

Back-up or maintenance service provided by an electric utility replaces energy or capacity which a qualifying facility ordinarily supplies to itself. These rules authorize certain facilities to purchase and sell simultaneously. The amount of energy or capacity provided by an electric utility to meet the load of a facility which simultaneously purchases and sells will vary only in accordance with changes in the facility's load; interruptions in the facility's generation will be manifested as variations in purchases from the facility. In such a case, sales to the qualifying facility will not be back-up or maintenance service, but will be similar to the full-requirements service that would be provided if the facility were a non-generating customer.

Supplementary power is electric energy or capacity used by a facility in addition to that which it ordinarily generates on its own. Thus, a cogeneration facility with a capacity of ten megawatts might require five more megawatts from a utility on a continuing basis to meet its electric load of fifteen megawatts. The five megawatts supplied by the electric utility would normally be provided as supplementary power.

Back-up power is electric energy or capacity available to replace energy generated by a facility's own generation equipment during an unscheduled outage. In the example provided above, a cogeneration facility might contract with an electric utility for the utility to have available ten megawatts, should the cogenerator's units experience an outage.

Maintenance power is electric energy or capacity supplied during scheduled outages of the qualifying facility. By pre-arrangement, a utility can agree to provide such energy during periods when the utility's other load is low, thereby avoiding the imposition of large demands on the utility during peak periods.

Interruptible power is electric energy or capacity supplied to a qualifying facility subject to interruption by the electric utility under specified conditions. Many utilities have utilized interruptible service to avoid expensive investment in new capacity that would otherwise be necessary to assure adequate reserves at time of peak demand. Under this approach utilities assure the adequacy of reserves by arranging to reduce peak demand, rather than by adding capacity. Interruptible service is therefore normally provided at a lower rate than non-interruptible service.

During the Commission's public hearings on this rulemaking, one commenter stated that utilities which have excess capacity do not save any costs by providing interruptible service. The commenter contended that the Commission should not require a utility with excess capacity to offer interruptible service. If a utility is not adding capacity (whether by construction or purchase) to meet anticipated increases in peak demand, the rates charged for interruptible service might appropriately be the same as for non-interruptible services.

The Commission believes that these matters involving the provision of interruptible rates are best handled through the pricing mechanism. However, if as discussed above, interruptible customers provide no savings to the electric utility, the rate for interruptible service need not be lower than the rate for firm service. In such a case, the Commission would consider granting a waiver from this paragraph, under the provisions of § 292.403.

Some comments noted that certain electric utilities do not have any generating capacity, and to require the services listed in subparagraph (1) might place an undue burden on the electric utility. In light of these comments, the State regulatory authorities or the Commission, as the case may be, will allow a waiver of these requirements upon a finding after a showing by the utility to the State regulatory authority or Commission, as the case may be, that provision of these services will impair the utility's ability to render adequate service to its customers or place an undue burden on the electric utility. Notice must be given in the area served by the electric utility, opportunity for public comment must be provided, and an application must be submitted to the State regulatory authority with respect to any electric utility over which it has ratemaking authority or the Commission with respect to any nonregulated electric utility.

Paragraph (c)(1) provides that rates for sales of back-up or maintenance power shall not be based, without factual data, on the assumption that forced outages or other reductions in output by each qualifying facility on an electric utility's system will occur either simultaneously or during the system peak. Like other customers, qualifying facilities may well have intraclass diversity. In addition, because of the variations in size and load requirements among various types of qualifying facilities, such facilities may well have interclass diversity.

The effect of such diversity is that an electric utility supplying back-up or maintenance power to qualifying facilities will not have to plan for reserve capacity to serve such facilities on the assumption that every facility will use power at the same moment. The Commission believes that probabilistic analyses of the demand of qualifying facilities will show that a utility will probably not need to reserve capacity on a one-to-one basis to meet back-up requirements. Paragraph (c)(1) prohibits utilities from basing rates on the assumption that qualifying facilities will impose demands simultaneously and at system peak unless supported by factual data.

The rule provides that utilities may refute these assumptions on the basis of factual data. These data need not be in the form of empirical load data. It might be the case that within certain geographic areas, weather data and performance data would constitute a sufficient basis to refute the assumption relating to the coincidence of the demands imposed, for example, by windmills or photovoltaics, with respect to their need for back-up power.

Paragraph (c)(2) provides that rates for sales shall take into account the extent to which a qualifying facility can usefully coordinate periods of scheduled maintenance with an electric utility. If a qualifying facility stays on line when the utility will need its capacity, and schedules maintenance when the utility's other units are operative, the qualifying facility is more valuable to the utility, as it can reduce its capacity requirements.

§ *292.306 Interconnection costs.*

Paragraph (a) states that each qualifying facility must reimburse any electric utility which purchases capacity or energy from the qualifying facility for any interconnection costs, on a nondiscriminatory basis with respect to other customers with similar load characteristics. The Commission finds merit in those comments which suggested that the basis of comparison for nondiscriminatory practices in the proposed rule to "any other customer" was too broad, and that the correct reference for nondiscrimination is the practice of the utility in relation to customers in the same class who do not generate electricity. As noted previously, the interconnection costs of a facility which is already interconnected with the utility for purposes of sales are limited to any additional expenses incurred by the utility to permit purchases.

Several commenters expressed their concern that some protection should be provided to qualifying facilities from potential harassment by utilities in the form of requiring unnecessary safety equipment. As discussed above, the State regulatory authorities (with respect to electric utilities over which they have ratemaking authority) and nonregulated electric utilities have the responsibility and authority to ensure that the interconnection requirements are reasonable, and that associated costs are legitimately incurred.

For qualifying facilities with a design capacity of 100 kW or less, the Commission noted that interconnection costs could be assessed on a class basis, and the standard rates for purchases established for classes of facilities of this size pursuant to § 292.304(c)(1) might incorporate these costs. State regulatory authorities (with respect to electric utilities over which they have ratemaking authority) or nonregulated electric utilities may also determine interconnection costs for qualifying facilities with a design capacity of more than 100 kW on either a class average or individual basis.

Numerous comments raised the point that the proposed rule did not address the manner in which electric utilities would be reimbursed. Potential owners and developers of qualifying facilities recommended that the costs be amortized on a reasonable basis, because paying a large lump sum payment would be a considerable obstacle to the program. Electric utilities generally preferred payment up front, although several commenters indicated that amortization might be acceptable for credit-worthy facilities. The Commission believes that the manner of reimbursements (which may include amortization over a reasonable period of time) is best left to the State regulatory authorities and nonregulated utilities. In the determination of any standard rates for purchases established pursuant to § 292.304(c)(i), if the State approves some manner of amortization, it might consider assignment of uncollected interconnection costs to the class for which the rate is established.

§ *292.307 System emergencies.*

Paragraph (a) provides that, except as provided under section 202(c) of the Federal Power Act, no qualifying facility shall be compelled to provide energy or capacity to the electric utility during an emergency beyond the extent provided by agreement between the qualifying facility and the utility.

The Commission finds that a qualifying facility should not be required to make available all of its generation to the utility during a system emergency. Such a requirement might interrupt industrial processes with resulting damage to equipment and manufactured goods. Many industries install their own generating equipment in order to ensure that even during a system emergency, their supply of power is not interrupted. To put in jeopardy the availability of power to a qualifying facility during a system emergency because of the facility's ability to provide power to the system during non-emergency periods would result in the discouragement of interconnected operation and a resultant discouragement of cogeneration and small power production. The Commission therefore provides that the qualifying facility's obligation to provide energy and capacity in emergencies be established through contract.

In order to receive full credit for capacity, a qualifying facility must offer energy and capacity during system emergencies to the same extent that it has agreed to provide energy and capacity during non-emergency situations. For example, a 30 megawatt cogenerator may require 20 megawatts for its own industrial purposes, and thus may contract to provide 10 megawatts of capacity to the purchasing utility. During an emergency, the cogenerator must provide the 10 megawatts contracted for to the utility; it need not disrupt its industrial processes by supplying its full capability of 30 megawatts. Of course, if it should so desire, a cogenerator could contractually agree to supply the full 30 megawatts during system emergencies. The availability of such additional backup capacity should increase utility system reliability, and should be accounted for in the utility's rates for purchases from the cogenerator.

Paragraph (b) provides that an electric utility may discontinue purchases from a qualifying facility during a system emergency if such purchases would contribute to the emergency. In addition, during system emergencies, a qualifying facility must be treated on a nondiscriminatory basis in any load shedding program—*i.e.*, on the same basis that other customers of a similar class with similar load characteristics are treated with regard to interruption of service.

Credit for capacity (as noted in § 292.304(e)(2)(v)) will also take into account the ability of the qualifying facility to separate its load and generation during system emergencies. However, the qualifying facility may well be eligible for some capacity credit even if it cannot separate its load and generation.

§ *292.308 Standards for operating reliability.*

Section 210(a) of PURPA states that the rules requiring electric utilities to buy from and sell to qualifying facilities shall include provisions respecting minimum reliability of qualifying facilities (including reliability of such facilities during emergencies) and rules respecting reliability of electric utilities during emergencies. The Commission believes that the reliability of qualifying facilities can be accounted for through price; namely, the less reliable a qualifying facility might be, the less it should be entitled to receive for purchases from it by the utility.

As a result, the Commission has not included specific standards relating to the reliability in the sense of the ability of qualifying facilities to provide energy or capacity.

The Commission has determined that safety equipment exists which can ensure that qualifying facilities do not energize utility lines during utility outages. This section accordingly provides that each State regulatory authority or nonregulated electric utility may establish standards for interconnected operation between electric utilities and qualifying facilities. These standards may be recommended by any utility, any qualifying facility, or any other person. These standards must be accompanied by a statement showing the need for the standard on the basis of system safety and operating requirements.

Subpart D—Implementation

Summary of this Subpart

Rules in this subpart are intended to carry out the responsibility of the Commission to encourage cogeneration and small power production by clarifying the nature of the obligation to implement the Commission's rules under section 210.

These rules afford the State regulatory authorities and nonregulated electric utilities great latitude in determining the manner of implementation of the

Commission's rules, provided that the manner chosen is reasonably designed to implement the requirements of Subpart C. The Commission recognizes that many States and individual nonregulated electric utilities have ongoing programs to encourage small power production and cogeneration. The Commission also recognizes that economic and regulatory circumstances vary from State to State and utility to utility. It is within this context—in recognition of the work already begun and of the variety of local conditions—that the Commission promulgates its regulations requiring implementation of rules issued under section 210.

Because of the Commission's desire not to create unnecessary burdens at the State level, these rules provide a procedure whereby a State regulatory authority or nonregulated electric utility may apply to the Commission for a waiver if it can demonstrate that compliance with certain requirements of Subpart C is not necessary to encourage cogeneration or small power production and is not otherwise required under section 210.

Several commenters expressed their concern that State regulatory authorities would not be able adequately to implement the Commission's rules, and therefore, recommended that the Commission issue specific rules which the State regulatory authorities would adopt without change. The Commission does not find this proposal to be appropriate at this time, and believes that providing an opportunity for experimentation by the States is more conducive to development of these difficult rate principles.

Implementation

Section 210(f) of PURPA requires that within one year after the date that this Commission prescribes its rules under subsection (a), and within one year of the date any of these rules is revised, each State regulatory authority and each nonregulated electric utility, after notice and opportunity for hearing, must implement the rules or revisions thereof, as the case may be.

The obligation to implement section 210 rules is a continuing obligation which begins within one year after promulgation of such rules. The requirement to implement may be fulfilled either (1) through the enactment of laws or regulations at the State level, (2) by application on a case-by-case basis by the State regulatory authority, or nonregulated utility, of the rules adopted by the Commission, or (3) by any other action reasonably designed to implement the Commission's rules.

Review and Enforcement

Section 210(g) of PURPA provides one of the means of obtaining judicial review of a proceeding conducted by a State regulatory authority or nonregulated utility for purposes of implementing the Commission's rules under section 210. Under subsection (g), review may be obtained pursuant to procedures set forth in section 123 of PURPA. Section 123(c)(1) contains provisions concerning judicial review and enforcement of determinations made by State regulatory authorities and nonregulated utilities under Subtitle A, B, or C of Title I in the appropriate State court. These provisions also apply to review of any action taken to implement the rules under section 210. This means that persons can bring an action in State court to require the State regulatory authorities or nonregulated utilities to implement these regulations.

Section 123(c)(2) of PURPA provides that persons seeking review of any determination made by a Federal agency may bring an action in the appropriate Federal court. This distinction between Federal agencies and non-Federal agencies also applies to review of enforcement of the implementation of the rules under section 210.

Finally, the Commission believes that review and enforcement of implementation under section 210 of PURPA can consist not only of review and enforcement as to whether the State regulatory authority or nonregulated electric utility has conducted the initial implementation properly—namely, put into effect regulations implementing section 210 rules or procedures for that implementation, after notice and an opportunity for a hearing. It can also consist of review and enforcement of the application by a State regulatory authority or nonregulated electric utility, on a case-by-case basis, of its regulations or of any other provision it may have adopted to implement the Commission's rules under section 210.

Section 210(h)(2)(A) of PURPA states that the Commission may enforce the implementation of regulations under section 210(f). The Congress has provided not only for private causes of action in State courts to obtain judicial review and enforcement of the implementation of the Commission's rules under section 210, but also provided that the Commission may serve as a forum for review and enforcement of the implementation of this program.

§ *292.401 Implementation by state regulatory authorities and nonregulated electric utilities*

Paragraph (a) of § 292.401 sets forth the obligation of each State regulatory authority to commence implementation of Subpart C within one year of the date these rules take effect. In complying with this paragraph the State regulatory authorities are required to provide for notice of and opportunity for public hearing. As described in the summary of this subpart, such implementation may consist of the adoption of the Commission's rules, an undertaking to resolve disputes between qualifying facilities and electric utilities arising under Subpart C, or any other action reasonably designed to implement Subpart C.

This section does not cover one provision of Subpart C which is not required to be implemented by the State regulatory authority or nonregulated electric utility. This provision is § 292.302 (Availability of electric utility system cost data), the implementation of which is subject to § 292.402, discussed below.

Subsection (b) sets forth the obligaton of each nonregulated electric utility to commence, after notice and opportunity for public hearing, implementation of Subpart C. The nonregulated electric utilities, being both the regulator and the utility subject to the regulation, may satisfy the obligation to commence implementation of Subpart C through issuance of regulations, an undertaking to comply with Subpart C, or any other action reasonably designed to implement that subpart.

Paragraph (c) sets forth a reporting requirement under which each State regulatory authority and nonregulated electric utility is to file with the Commission, not later than one year after these rules take effect, a report describing the manner in which it is proceeding to implement Subpart C.

Comments received regarding this section indicated a concern that the obligation of a State regulatory authority or nonregulated utility "to commence implementation * * * within one year * * *" did not provide any guidance as to when the process must be completed. The Commission notes that the intention of this section is that the State regulatory authorities and nonregulated utilities have one year in which to establish procedures and that at the end of that year each State must be prepared to entertain applications. The phrase "commence implementation" is intended by the Commission to connote that implementation of these rules is a continuing process and that oversight will be ongoing.

§ *292.402 Implementation of reporting objectives.*

The obligation to comply with § 292.302 is imposed directly on electric utilities. This is different from the rest of Subpart C where the obligation to act is imposed on the State regulatory authority or the nonregulated electric utility in its role as regulator. The Commission is exercising its authority under section 133 of PURPA and other laws within the Commission's authority to require this reporting.

Any electric utility which fails to comply with the requirements of § 292.302(b) is subject to the same penalties as it might receive as a result of a failure to comply with the requirements of the Commission's regulations issued under section 133 of

PURPA. As stated earlier in this preamble, the data required by § 292.302 will form the basis from which the rates for purchases will be derived; § 292.302 is thus a critical element in this program. The Commission believes that, with regard to utilities subject to section 133 of PURPA, the Commission may exercise its authority under section 133 to require the data required by § 292.302(b) on the basis that the Commission finds such information necessary to allow determination of the costs associated with providing electric services. With regard to utilities not subject to section 133, if they fail to provide the data called for in § 292.302(c), the Commission may compel its production under the Federal Power Act and other statutes which provide the Commission with authority to require reporting of such data.

§ *292.403 Waivers.*

Paragraph (a) provides for a procedure by which any State regulatory authority or nonregulated electric utility may apply for a waiver from the application of any of the requirements of Subpart C other than § 292.302. (Section 292.302(d) has been revised to permit a State regulatory authority or nonregulated utility to adopt a substitute method for the provision of system cost data without prior Commission approval.)

Paragraph (b) provides that the Commission will grant such a waiver only if the applicant can show that compliance with any of the requirements is not necessary to encourage cogeneration or small power production and is not otherwise required under section 210 of PURPA.

This section is included in recognition of the need for the Commission to afford flexibility to the States and nonregulated utilities to implement the Commission's rules under section 210.

Several comments suggested that the Commission set forth procedures for considering applications for waivers which would allow formal participation by qualifying facilities in a public hearing. The Commission notes that interested parties would be given an opportunity to be heard in any proceeding it conducts to determine whether or not a waiver should be granted.

Subpart F—Exemption of Qualifying Small Power Production and Cogeneration Facilities From Certain Federal and State Laws and Regulations

§ *292.601 Exemption of qualifying facilities from the Federal Power Act.*

Section 210(e) of PURPA states that the Commission shall prescribe rules under which qualifying facilities are exempt, in part, from the Federal Power Act, from the Public Utility Holding Company Act of 1935, from the State laws and regulations respecting the rates, or respecting the financial or organization regulation, of electric utilities, or from any combination of the foregoing, if the Commission determines such exemption is necessary to encourage cogeneration and small power production. As noted in the Staff Discussion Paper, the Congress intended the Commission to make liberal use of its exemption authority in order to remove the disincentive of utility-type regulation. The Commission believes that broad exemption is appropriate.

Section 210(e)(2) of PURPA provides that the Commission is not authorized to exempt small power production facilities of 30 to 80 megawatt capacity from these laws. An exception is made for small power production facilities using biomass as a primary energy source. Such facilities between 30 and 80 megawatts may be exempted from the Public Utility Holding Company Act of 1935 and from State laws and regulations but may not be exempted from the Federal Power Act. The Commission will establish procedures for the determination of rates for these facilities in a separate proceeding.

Paragraph (a) sets forth those facilities which are eligible for exemption. Paragraph (b) provides that facilities described in paragraph (a) shall be exempted from all but certain specified sections of the Federal Power Act.

Section 210(e)(3)(C) of PURPA provides that no qualifying facility may be exempted from any license or permit requirement under Part I of the Federal

Power Act. Accordingly, no qualifying facilities will be exempt from Part I of the Federal Power Act. The Commission recently issued simplified procedures for obtaining water power licenses for hydroelectric projects of 1.5 megawatts or less, and has issued proposed regulations to expedite licensing of existing facilities.[21]

The Commission believes cogeneration and small power production facilities could be the subject of an order under section 202(c) of the Federal Power Act requiring them to provide energy if the Economic Regulatory Administration determines that an emergency situation exists. Because application of this section is limited to emergency situations and is not affected by the fact that a facility attains qualifying status or engages in interchanges with an electric utility, the Commission notes that qualifying facilities will not be exempted from section 202(c) of the Act.

Furthermore, in response to comment, the Commission has revised this paragraph to provide that qualifying facilities are not exempt from sections 210, 211, and 212 of the Federal Power Act, as required by section 210(e)(3)(B) of PURPA.

Sections 203, 204, 205, 206, 208, 301, 302, and 304 of the Federal Power Act reflect traditional rate regulation or regulation of securities of public utilities. The Commission has determined that qualifying facilities shall be exempted from these sections of the Federal Power Act.

Section 305(c) of the Act imposes certain reporting requirements on interlocking directorates. The Commission believes that any person who otherwise is required to file a report regarding interlocking positions should not be exempted from such requirement because he or she is also a director or officer of a qualifying facility.

Finally, the enforcement provisions of Part III of the Federal Power Act will continue to apply with respect to the sections of the Federal Power Act from which qualifying facilities are not exempt.

§ *292.602 Exemption of qualifying facilities from the Public Utility Holding Company Act and certain State law and regulation.*

Under section 210(e) of PURPA the Commission can exempt qualifying facilities from regulation under the Public Utility Holding Company Act of 1935 and State laws and regulations concerning rates or financial organization. Only cogeneration facilities and small power production facilities of 30 megawatts or less may be exempted from both of these laws, with the exception that any qualifying small power production facility (*i.e.*, up to 80 megawatts) using biomass as a primary energy source can be exempted from these laws.

The Commission has determined that where a qualifying facility is subjected to more stringent regulation than other companies solely by reason of the fact that it is engaged in the production of electric energy, these more stringent requirements should be eased through exemption of qualifying facilities. By excluding any qualifying facility from the definition of an "electric utility company" under section 2(a)(3) of the Public Utility Holding Company Act of 1935, such facilities would be removed from Public Utility Holding Company Act regulation which is applied exclusively to electric utility companies. Moreover, by excluding qualifying facilities from this definition, parent companies of qualifying facilities would not be subject to additional regulation as a result of electric production by their subsidiaries. The Commission therefore believes that in order to encourage cogeneration and small power production it is necessary to exempt cogenerators and small power producers from all of the provisions of the Public Utility Holding Company Act of 1935 related to electric utilities.

Accordingly, paragraph (b) states that no qualifying facility shall be considered to be an "electric utility company", as defined in section 2(a)(3) of the Public Utility Holding Company Act of 1935, 15 U.S.C. § 79b(a)(3).

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[21] *See* Order No. 11, Simplified Procedures for Certain Water Power Licenses, Docket No. RM79-9, issued September 5, 1978, and Application for License for Major Projects—Existing Dam, Docket No. RM79-36, 44 FR 24095 (April 21, 1979).

Section 210(e) of PURPA states that qualifying facilities which may be exempted from the Public Utility Holding Company Act may also be exempted from State laws and regulations respecting the rates or financial organization of electric utilities.

The Commission has decided to provide a broad exemption from State laws and regulations which would conflict with the State's implementation of the Commission's rules under section 210.

The Commission believes that such broad exemption is necessary to encourage cogeneration or small power production. Accordingly, subparagraph (c)(1) provides that any qualifying facility shall be exempt from State laws and regulations respecting rates of electric utilities, and from financial and organizational regulation of electric utilities. Several commenters noted that this section might be interpreted as exempting qualifying facilities from state laws or regulations implementing the Commission's rules, under section 210(f) of PURPA. In order to clarify that qualifying facilities are not to be exempt from these rules, the Commission has added subparagraph (c)(2) prohibiting any exemptions from State laws and regulations promulgated pursuant to Subpart C of these rules.

Some commenters indicated that § 292.301(b)(1) might be interpreted as prohibiting a State from reviewing contracts for purchases. These commenters stated that, as a part of a State's regulation of electric utilities, a State regulatory authority needs to be able to review contracts entered into by electric utilities it regulates.

These rules, and the exemptions being provided by these rules, are not intended to divest a State regulatory agency of its authority under State law to review contracts for purchases as part of its regulation of electric utilities. Such authority may continue to be exercised if consistent with the terms, policies and practices under sections 210 and 201 of PURPA and this Commission's implementing regulations. If the authority or its exercise is in conflict with these sections of PURPA or the Commission's regulations thereunder, the State must yield to the Federal requirements. The Commission does not believe it possible or advisable to attempt to establish more precise guidelines than these. Accordingly, States which have questions in this regard should seek an interpretive ruling from the Commission's General Counsel.

Subparagraph (c)(3) provides that, upon request of a State regulatory authority or nonregulated electric utility, the Commission may limit the applicability of the broad exemption from the State laws. This provision is intended to add flexibility to the exemption.

The Commission perceives that there may be instances in which a qualifying facility would wish to have an interpretation of whether or not it is subject to a particular State law in order to remove any uncertainty. Under subparagraph (c)(4), the Commission may determine whether a qualifying facility is exempt from a particular State law or regulation.

(Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 2601, *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. § 791 *et seq.*, Federal Power Act, as amended, 16 U.S.C. § 792 *et seq.*, Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.*, E.O. 12009, 42 Fed. Reg. 46267)

IV. Effective Date

The regulations promulgated in this order are effective March 20, 1980.

In consideration of the foregoing, the Commission amends Part 292 of Chapter I, Title 18, Code of Federal Regulations, as set forth below, effective March 20, 1980. By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,129]

45 F. R. 12409 (February 26, 1980)

18 CFR Part 274

[Docket No. RM79-3]

U.S. Geological Survey Application for Alternative Filing Requirements; Order Issuing Alternative Filing Requirements

February 19, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: This rule amends 274.208(a) of the Federal Energy Regulatory Commission's regulations implementing the Natural Gas Policy Act of 1978 to provide alternative filing requirements for certain well determination applications to the United States Geological Survey in New Mexico. This amendment allows alternative filing requirements which apply to applications filed with the New Mexico jurisdictional agency to also apply to applications filed with the United States Geological Survey. This action is taken as a result of a petition from the Geological Survey.

EFFECTIVE DATE: February 19, 1980.

FOR FURTHER INFORMATION CONTACT: Mark Magnuson, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357-8511.

SUPPLEMENTARY INFORMATION:

On November 6, 1979, the United States Geological Survey (USGS) filed an application with the Federal Energy Regulatory Commission (Commission) for approval of alternative filing requirements pursuant to § 274.207 of the Commission's regulations. The proposed alternative filing requirements would apply to a producer seeking a determination that a well drilled in an existing proration unit in the Blanco-Mesaverde or Basin-Dakota pools in New Mexico is a new, onshore production well. Notice of the USGS application was issued on November 20, 1979,[1] and the comment period expired on November 28, 1979. No comments were filed.

Section 103 of the Natural Gas Policy Act of 1978 (NGPA) establishes the maximum lawful prices applicable to natural gas from new, onshore production wells. An applicant seeking a determination of eligibility to collect the section 103 price is required to file with the appropriate jurisdictional agency the information specified in § 274.204 of the Commission's regulations,unless the Commission has approved alternative filing requirements pursuant to § 274.207. In its application, USGS requests that the filing requirements of § 274.204(f)[2] be waived, and that alternative filing requirements be established with respect to applications for section 103 determinations for infill wells[3] drilled in accordance with the USGS Area Oil and Gas Supervisor's ratification of New Mexico Oil Conservation Division Order Nos. R-1607-T (regarding the Blanco-Mesaverde pool) and R-1670-V (regarding the Basin-Dakota pool).[4]

In Order No. 66, the Commission established alternative filing requirements applicable to applications filed with the New Mexico jurisdictional agency for section 103 eligibility determinations for wells located within the Blanco-Mesaverde and Basin-Dakota pools underlying New Mexico lands.[5] However, portions of the subject gas pools underlie Federal or Indian lands, so that in some cases, applications for determinations for wells within those pools must be filed with the USGS, rather than with the New Mexico jurisdictional agency.[6] This order is therefore necessary to allow all applicants for section 103 determinations for infill wells drilled in the subject gas pools to utilize the same alternative filing requirements.

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[1] 44 FR 68521 (Nov. 29, 1979).

[2] Section 274.204(f) requires, in part, that the applicant who is seeking a section 103 determination for a new well which is drilled in an existing proration unit, submit "appropriate geological evidence and engineering data [to demonstrate] that the new well is necessary to effectively and efficiently drain a portion of the reservoir covered by the proration unit which cannot be effectively and efficiently drained by any existing well within the proration unit."

[3] An infill well is a well which, for geological reasons, is necessary to drain a portion of a reservoir which is not being effectively and efficiently drained by any existing wells in the reservoir.

[4] In Order No. R-1670-T, New Mexico found, inter alia:

(12) That the producing formation of the Blanco-Mesaverde Pool is comprised of various overlapping, interconnecting, and lenticular sands of relatively low permeability, many of which are not being efficiently drained by existing wells in the pool but which could be more efficiently and economically drained and developed by the drilling of additional wells pursuant to the rule changes proposed by the applicant.

In Order No. R-1670-V, New Mexico found, inter alia:

(13) That the producing formation of the Basin-Dakota Gas Pool is comprised of various sands of low permeability and porosity which are not being efficiently and effectively drained by existing wells in the various proration units in the pool, and which can be more efficiently and effectively drained by the drilling of additional wells pursuant to the rule changes proposed by the applicant.

(14) That the infill drilling of a second well on an established proration unit in the Basin-Dakota Gas Pool is necessary to effectively and efficiently drain a portion of the reservoir covered by the proration unit which cannot be effectively and efficiently drained by any existing wells within the proration unit.

Accordingly, the Commission is amending Part 274, Subpart B in § 274.208(a) so that the alternative filing requirements which apply to applications filed with the New Mexico jurisdictional agency shall also apply to applications filed with USGS.

The alternative filing requirements approved in Order No. 66 are based upon the Commission's review of New Mexico Order Nos. R-1670-T and R-1670-V, in which New Mexico found that an infill drilling program on a poolwide basis in the two subject pools was necessary to effectively and efficiently drain the proration units in those pools.[7] The finding by New Mexico was made on the record, which was comprised of geological and engineering data submitted under oath at the hearing.

The Commission, in Order No. 66, determined that the New Mexico findings were supported by substantial evidence, and thereupon approved alternative filing requirements which permit applicants requesting section 103 determinations for wells drilled in the subject pools to reference the appropriate New Mexico order, rather than submit the data required under § 274.204(f). Also, because Order Nos. R-1670-T and R-1670-V constitute the explicit effective and efficient drainage finding required by § 271.305(b), the Commission waived the requirements of § 271.305(b) that such data be included in the notice of determination and of § 271.305(c) that the jurisdictional agency notify the Commission of its finding. Finally, the oath statement required of an applicant under § 274.204(a)(4) was modified to conform to the modifications in filing requirements.[8]

USGS has ratified New Mexico Order Nos. R—1670-T and R-1670-V [9] and has complied with the provisions of § 274.207, which set forth the requirements for an application for approval of alternative filing requirements. In approving the USGS application, the Commission finds that an infill drilling program is necessary to effectively and efficiently drain the proration units in the Blanco-Mesaverde and Basin-Dakota pools underlying Federal or Indian lands in New Mexico and that the determinations in this respect implicit in the USGS ratifications of New Mexico Order Nos. R-1670-T and R-1670-V are supported by substantial evidence. On this basis, the Commission hereby provides that the alternative filing requirements currently applicable to applications for section 103 eligibility determinations for infill wells drilled in the Blanco-Mesaverde or Basin-Dakota pools underlying New Mexico lands shall also be applicable to any section 103 determinations for infill wells drilled in the same pool underlying Federal or Indian lands.

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[5] Order Issuing Alternative Filing Requirements, Docket No. RM79-3, issued January 4, 1980.

[6] The USGS Area Oil and Gas supervision is the jurisdictional agency for wells drilled on Federal or Indian lands in New Mexico.

[7] Certified copies of records relied on by New Mexico in adopting its poolwide infill well orders were included with the New Mexico application for alternative filing requirements and are incorporated by reference in the USGS proposal.

[8] Because applications which reference the appropriate New Mexico order would contain no further documentation in support of the required effective and efficient drainage finding, the requirement of § 274.204(d)(4) that the applicant state under oath that "*on the basis of the documents submitted in the application*, the applicant has concluded that to the best of his information, knowledge and belief, the natural gas for which he seeks a determination is produced from a new, onshore production well" (emphasis added), was modified to omit the requirement that the applicant's conclusion be based on "documents submitted in the application."

[9] See attached Appendix A.

Public Procedures and Effective Date

A notice regarding the USGS application was issued on November 20, 1979. The Commission stated that comments on the proposed plan would be accepted if received on or before November 28, 1979. No comments were received. In view of the above discussion, the Commission approves the USGS alternative plan set forth in its application with modifications noted above.

The Commission believes that good cause exists to make the alternative plan effective immediately for all determinations which have not yet become final under § 275.202 as of the day before the date of issuance of this order.

(Natural Gas Act, as amended, 15 U.S.C. § 717 *et seq.;* Department of Energy Organization Act, 42 U.S.C. § 7107, et seq.; Exec. Order No. 12009, 42 Fed. Reg. 46267; Natural Gas Policy Act of 1978, 15 U.S.C. § 3301, et seq.;)

In consideration of the foregoing, Part 274 of Subchapter H, Chapter I, Title 18, Code of Federal Regulations is amended as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

Appendix A

U.S. Department of the Interior,
Geological Survey,
Albuquerque, N. Mex.

Notice

To all Lessees and Operators on Federal and Indian Oil and Gas Leases in the Southern Rocky Mountain Area

On December 1, 1978, the Federal Energy Regulatory Commission (FERC) promulgated its "Interim Regulations Implementing the Natural Gas Policy Act of 1978." Subpart "C" of the regulations implements Section 103 of the Natural Gas Policy Act and applies to natural gas produced from a "new, onshore production well."

Section 271.305(a)(b) of the regulations provides as follows:

"In order for natural gas from a well to which this paragraph applies to qualify for the maximum lawful price under this subpart, the jurisdictional agency must find, *prior to the commencement of drilling,* that the well is necessary to effectively and efficiently drain

a portion of the reservoir or covered by the proration unit which cannot be effectively and efficiently drained by any existing well within the proration unit. Such finding must be explicit and must involve either a redefinition of the boundaries of the previously existing proration unit or an alteration of or exception to otherwise applicable well-spacing rules."

The New Mexico Oil Conservation Commission (now the New Mexico Oil Conservation Division, (NMOCD)) on November 14, 1974, issued Order No. R-1670-T, permitting the optional drilling of an additional well on 320-acre proration units in the Blanco Mesaverde Pool, San Juan and Rio Arriba Counties, New Mexico. The Area Oil and Gas Supervisor, Southern Rocky Mountain Area, to conserve natural resources and protect the rights of Federal and Indian lands, ratified Order No. R-1670-T effective November 14, 1974, insofar as Federal and Indian lands are concerned. Accordingly, applications to this Agency for category determinations for new Blanco Mesaverde Pool wells in existing proration units under Section 103 of the Act should include copies of this ratification and NMOCD Order R-1670-T.

James W. Sutherland
Oil and Gas Supervisor, Southern Rocky Mountain Area, February 22, 1979

United States Department of the Interior,
Geological Survey,
Albuquerque, N. Mex.

Notice

To all Lessees and Operators on Federal and Indian Oil and Gas Leases in the Southern Rocky Mountain Area

On December 1, 1978, the Federal Energy Regulatory Commission (FERC) promulgated its "Interim Regulations Implementing the Natural Gas Policy Act of 1978." Subpart "C" of the regulations implements Section 103 of the Natural Gas Policy Act and applies to natural gas produced from a "new, onshore production well."

Section 271.305(a)(b) of the regulations provides as follows:

"In order for natural gas from a well to which this paragraph applies to qualify for the maximum lawful price under this subpart, the jurisdictional agency must find, *prior to the commencement of drilling,* that the well is necessary to effectively and efficiently drain a portion of the reservior covered by the proration unit which cannot be effectively and efficiently drained by any existing well within the proration unit. Such finding must be explicit and must involve either a redefinition of the boundaries of the previously existing proration unit or an alteration of or exception to otherwise applicable well-spacing rules."

The New Mexico Oil Conservation Commission (now the New Mexico Oil Conservation Division, (NMOCD)) on May 22, 1979, issued Order No. R-1670-V, effective July 1, 1979, permitting the optional drilling of an additional well on 320-acre proration units in the Basin Dakota Gas Pool, San Juan and Rio Arriba Counties, New Mexico. The Area Oil and Gas Supervisor, Southern Rocky Mountain Area, to conserve natural resources and protect the rights of Federal and Indian lands, ratifies Order No. R-1670-V effective July 1, 1979, insofar as Federal and Indian lands are concerned. Accordingly, applications to this Agency for category determinations for new Basin Dakota Gas Pool wells in existing proration units under Section 103 of the Act should include copies of *this ratification* and NMOCD Order R-1670-V.

James W. Sutherland
Oil and Gas Supervisor, Southern Rocky Mountain Area, June 8, 1979.

[¶ 30,130]

45 F. R. 13414 (February 28, 1980)

18 CFR Parts 271, 273, and 274

[Docket No. RM79-76]

Interim Rule Covering High-Cost Natural Gas Produced From Tight Formations

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Interim Rule and Request for Further Comment.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts interim rules implementing section 107(b) and (c)(5) of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3317). Section 107 of the NGPA permits the Commission to identify gas which is produced under extraordinary risk or cost and to establish the maximum lawful price "necessary to provide reasonable incentives for the production" of such gas. This interim rule establishes gas produced from certain wells in tight formations as a category of high-cost natural gas subject to incentive pricing and establishes the procedures for identifying such gas. In a proposed rule document published elsewhere in this Part of the Federal Register, the Commission seeks further comment on whether incentive prices should be extended to most other tight formation gas.

DATES: This rule will be effective March 21, 1980. Written comments must be submitted by March 28, 1980.

ADDRESS: Written comments should reference Docket No. RM79-76 and should be sent to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

Teresa Ponder, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357-8151, or

Howard Kilchrist, Director, Division of NGPA Compliance, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357-8585.

February 20, 1980.

I. Introduction and Summary

The Federal Energy Regulatory Commission firmly supports the national policy to encourage production of natural gas from unconventional sources. Such gas typically can be discovered and produced only at extraordinary risk or cost. One such source of unconventional gas is a fairly common geological structure known as a "tight formation" or "tight sands."

The interim regulations promulgated by this order implement the Congressional authorization to the Commission in section 107(b) of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3317) to set a "special price" which is "necessary to provide reasonable incentives for the production of * * * high-cost natural gas."

In these interim regulations, the Commission has set an incentive price for certain natural gas produced from tight formations. The regulations contain guidelines for identifying and formally designating tight formations and define which wells drilled into such formations will qualify for the incentive price. Under the interim rule most new wells drilled into designated tight formations will be eligible for the incentive price.

A "tight formation" is a sedimentary layer of rock composed of very fine and irregularly shaped grains of sand cemented together in a way which greatly hinders the flow of gas through the rock. Hence, the formation is characterized by low permeability and wells drilled into gas-bearing formations of this kind generally produce at very low rates.

In order to stimulate production from these formations, producers must use expensive enhanced recovery techniques. The most common of these techniques involves massive hydraulic fracturing to create a system of cracks permitting trapped gas to flow into the wellbore more easily.

It is estimated that 200 trillion cubic feet of natural gas is trapped in tight formations within the United States. If the proper incentive is established, gas from tight sands could double the 200 trillion cubic feet of proven conventional domestic gas reserves. Most tight sands gas will come from reservoirs located west of the Mississippi. A substantial portion of these reserves are concentrated in three major basins: the Greater Green River Basin in Wyoming, the Piceance Basin in Colorado, and the Uinta Basin in Utah.

This rulemaking was initiated as a result of comments received in response to the Commission's Notice of Inquiry (Docket No. RM79-44, 44 FR 34969, June 18, 1979) which indicated that an incentive price was necessary to stimulate commercial development of tight sands gas. President Carter, in his energy address to the nation on July 19, 1979, also urged the Commission to set such an incentive. A Notice of Proposed Rulemaking was issued August 29, 1979 (Docket No. RM79-76, 44 FR 52255, September 7, 1979). Public hearings were held in Washington, D.C. on September 24th and in Denver, Colorado, on September 27, and numerous written comments were received. In addition, input was solicited from the jurisdictional agencies that will participate in administration of these regulations and from other expert groups and individuals.

These interim regulations reflect a full and careful analysis of the comments received on the proposed regulations. Several changes to the proposed regulations were suggested in the comments, and a number of these suggestions have been adopted in the interim regulations. The most important changes were made in the procedure for designating tight formations eligible for the section 107 price. The procedure set forth in these interim regulations is based on nomination of specific formations by appropriate jurisdictional agencies. The procedure was instituted in order to utilize more fully the information and expertise available to jurisdictional agencies and to make the rules easier to administer.

The interim regulations provide that the appropriate agency in each State may recommend formations within that State which meet Commission specifications and therefore may be eligible to be designated by the Commission as tight formations. With the recommendations, the agency must submit supporting geological and engineering data, information locating all wells which have produced from the recommended formation, and other relevant data. After public comment, the Commission will formally designate eligible formations.

The guidelines for identifying tight formations set forth in these interim regulations include limits on permeability, gas productivity and production of associated oil. Eligibility of a formation under the permeability and production standards need not be proven on a well-by-well basis. Formal designation of a specific tight formation will be based on a jurisdictional agency's and the Commission's assessment of the general characteristics of the formation.

The Commission has set a permeability limit of an average of .1

millidarcy throughout the "pay" or gas-producing section of the formation. Permeability is an indicator of the difficulty and expense involved in producing gas from a given formation. The permeability of many formations is reasonably uniform and the average permeability can be reasonably estimated. The .1 millidarcy figure will encompass most recognized tight formations and is the lowest permeability that can be measured without expensive pressure tests.

The costs of drilling and completing gas wells increase exponentially with the depth of the well, so deeper wells must produce more to be economical. As a result, the Commission has set a gas productivity standard to be applied to tight formations before application of enhanced recovery techniques that varies with the depth of the formation.

In addition, a recommended tight formation may not be expected to produce more than five barrels of crude oil per day from each well. This limit has been imposed because the presence of oil in greater quantities should, in itself, provide an incentive for the development of the formation, obviating the necessity for additional incentives.

In order to qualify for the incentive price a well drilled into a designated tight formation must have been commenced on or after July 16, 1979. This date was selected in recognition of the President's policy initiative on tight sands.

The requirements in the proposed rule that tight sands status would not be granted to a formation if field rules have been established or use of enhanced recovery techniques is not required have not been included in the interim regulations. The Commission also considered but has rejected a one-mile spacing requirement for wells drilled into designated tight formations. These constraints were dropped either because they would be inconsistent with the need to provide production incentives or because they imposed unreasonable administrative requirements.

The Commission has decided initially to set the maximum lawful price for natural gas produced from new wells in tight formations at 150 percent of the Congressional ceiling price for gas from new conventional onshore production wells (as set forth in section 103 of the NGPA). This tight formation gas price is $3.26 per MMBtu in February 1980, and will be adjusted monthly for inflation. The Commission is soliciting further comments on the incentive price for this tight formation gas. If comments or further information shows that higher prices are necessary to encourage development of tight formations, the Commission will increase the price ceiling. As a general matter, the ceiling price for tight formation gas produced from new wells will not be decreased below 150 percent of the section 103 price.

The interim rules apply to new wells. However, substantial amounts (at least 100 trillion cubic feet) of tight formation gas may be trapped "behind-the-pipe", in reservoirs penetrated by old wells but never tapped. Although new wells would not have to be drilled to produce this gas, production is not entirely without risk. Accordingly, the Commission is considering a proposal to create a special incentive price for production of this gas. The price would equal the incentive price which the Congress fixed for conventional development under section 103. The Commission is also soliciting comments on this proposal.

A Staff task force has prepared an environmental assessment, finding that little impact on the environment will follow from development of tight formations. The Commission will continue to evaluate potential impacts as specific formations are designated.

These interim regulations will become effective on March 21, 1980.

II. Background

This rulemaking was initiated as a result of comments received in response to a Notice of Inquiry issued in Docket No. RM79-44 (44 FR 34969, June 18, 1979) and statements made by the President and the Secretary of Energy indicating a need to encourage development of this gas. A Notice of Proposed Rulemaking and Public Hearing was issued August

29, 1979, (44 FR 52255, September 7, 1979) in this docket.

The proposed rule preliminarily identified certain formations as candidates for designation as tight formations and outlined the following guidelines for identifying tight formations:

(1) An estimated average *in situ* gas permeability of 0.03 millidarcy per foot or less;

(2) Expected production without application of an enhanced production technique of 200 Mcf or less per day;

(3) Production expected to improve substantially after application of an enhanced recovery techniques; and

(4) No field rules established or requested for the formation or any portion thereof.

The proposal also specified what information would be required in order to determine whether a formation qualified as tight formation, and specified requirements for each individual well. The surface drilling of the well was to have begun on or after August 17, 1979; the well was to have qualified as a new, onshore production well; an appropriate enhanced production technique was to have been applied; and finally, the well was to have been drilled into a designated tight formation. The proposal also established filing requirements for applicants seeking such a well category determination. Finally, the maximum lawful price proposed was 150 percent of the maximum lawful price for section 103 gas.

The Commission invited comments on the proposal from interested persons and held informal public hearings in Washington, D.C. (on September 24th) and Denver, Colorado (on September 27th). The staff also circulated a subsequent draft of the rule among jurisdictional agencies and accepted comments on it at conferences with those agencies. Informal conferences were also held with members of the public who requested an opportunity to submit comments to Commission staff on that draft. In addition, representatives from the Commission attended a meeting of the Tight Gas Reservoirs Task Group of the National Petroleum Council's Committee on Unconventional Gas Sources in Las Vegas, Nevada, on January 9, 1980. Transcripts or minutes of the various conferences and meetings may be found in the public file on Docket No. RM79-76. In response to the comments received, the interim rule has been substantially changed from the proposal.

The interim rule promulgated in this order does not identify any formations which qualify as tight formations. It simply sets forth the guidelines for identifying tight formations and establishes the procedures whereby a jurisdictional agency may recommend (and the Commission may approve) the designation of a formation as a tight formation. The ceiling for the interim maximum lawful price is the same as that contained in the proposal; however, a price higher than the otherwise applicable maximum lawful price is not permitted unless a negotiated contract price is effective. A negotiated contract price is a price which is established by a fixed rate or a fixed escalator clause which is higher than the otherwise applicable maximum price, or a clause which specifically refers to the Commission's incentive pricing authority under section 107 of the NGPA. Thus, the maximum lawful price for the first sale tight formation gas is the lesser of the negotiated contract price or 150 percent of the section 103 maximum lawful price. The Commission requests further comment on the ceiling of 150 percent of the section 103 maximum lawful price and the negotiated contract price ceiling.

As in the proposal, the rule establishes production qualifications. First, such gas must have been produced from a designated tight formation. Second, the surface drilling date of the well has been changed to July 16, 1979. Therefore the surface drilling of any well producing gas which qualifies under this rule may not have begun prior to July 16, 1979. Third, the gas must qualify as new natural gas or be produced through a new onshore production well. Finally, the gas must be sold pursuant to a negotiated contract price. The rule limits the categories of tight formation gas which may obtain an incentive price to such gas. That category is identified as "new tight formation gas."

The Commission is considering (and requests further comment on) a proposal to establish a special incentive price for "recompletion tight formation gas." Such gas would include gas produced from a well which was not completed for production from the designated tight formation before July 16, 1979, if it were subject to a negotiated contract price. The maximum lawful price proposed for such gas would be the lesser of the negotiated contract price or the section 103 maximum lawful price.

III. Discussion of Comments

A. Procedure for Designating Tight Formations

The proposal listed possible tight formations, described the characteristics of tight formations and listed the information that would be required in considering further recommendations. The presumption underlying the proposal was that the Commission would identify tight formations pursuant to a rulemaking procedure based on information submitted to it by jurisdictional agencies and other interested parties.

One commenter contested the Commission's authority to make such substantive determinations relating to formation qualification. That comment argued that the Commission only has the authority to establish guidelines for identifying tight formations, but may not engage in determining which formations qualify. According to the comment the Commission's authority regarding identification of tight formations is limited to reviewing jurisdictional agencies' determinations pursuant to section 503 of the NGPA; *i.e.,* the Commission could reverse a jurisdictional agency's determination only if it were not supported by substantial evidence.

Other commenters suggested as a matter of policy that the jurisdictional agencies, not the Commission, should identify tight formations. These commenters suggested that the jurisdictional agencies have better access than the Commission to the information and expertise required to evaluate the geological and other physical characteristics of the local areas, as well as information on the extent and type of development that has already occurred in tight formations.

These comments were buttressed by other comments which informed the Commission that some of the formations listed in the proposed rule contain areas which are already fully developed and that others were incorrectly identified. Other comments suggested that only portions of formations should be designated since many tight formations contain areas which may be or have been commercially developed without incentive pricing.

The Commission does not believe that its authority to engage in the formation identification process is limited to a section 503 review of jurisdictional agencies' determinations. Section 503 describes the Commission's review authority only with respect to well category determinations. Moreover, pursuant to section 501 of the NGPA, the Commission has the authority to engage in any activity and to issue any rules it finds necessary to carry out its functions under the NGPA. One of the Commission's functions under section 107 is to identify gas which is produced under extraordinary risk or cost. Given that function, and its authority under section 501, the Commission is not constrained by section 503 as the commenter suggested.

Nonetheless, the Commission is convinced that the jurisdictional agencies have the best access to the production history and geological information relating to potential tight formations within each State's jurisdiction. Therefore this rule does not specifically identify tight formations.

Instead, it establishes guidelines for identification of tight formations. (Those guidelines are discussed *infra.)*

Tight formations or portions thereof in any basin, field, or field area will be determined according to procedures similar to those adopted for approving alternate filing requirements which appear in § 274.207. Jurisdictional agencies will establish procedures for and conduct their own investigations to identify tight formations and will submit their written recommendations to the Commission for approval. The recommendations will be submitted in the form and with the information required by this rule. Upon receipt of a recommendation the Commission will publish it in the Federal Register and will hold public hearings and accept written and oral comments on the recommendation. After the comments have been solicited and reviewed, the Commission will prescribe a rule approving or disapproving the recommendation. If the formation is approved, the Commission will incorporate the formation into the list of qualifying formations in a new § 271.706 of the regulations. The Commission's designation may represent a modification of the recommendation. However, such a modification will not be made until the jurisdictional agency has been consulted. Grounds for disapproving a recommendation may be based, among other things, on the Commission's determination that the formation does not satisfy the guidelines or that the information submitted with the recommendation does not fulfill the requirements contained in § 271.705(c). The Commission may also request additional information from the jurisdictional agencies.

Jurisdictional agencies should limit their recommendations to those geographical areas of a formation, and those strata which meet the guidelines. The jurisdictional agency should clearly identify the correct strata or geological formation if two or more formations, not all of which are tight, overlap each other.

The information which must be submitted with the recommendation is essentially the same type of information that was suggested in the proposal, namely: geological and engineering data to support the recommendation and the source of that data; a map which clearly locates all wells which have produced from the recommended tight formation or a list locating all wells that have produced natural gas from the recommended tight formation; a report of the extent to which existing State or Federal regulations will assure that development of the recommended tight formation will not adversely affect any fresh water aquifers that are or are expected to be used as a domestic or agricultural water supply; and any other information which the jurisdictional agency deems relevant. Additional information is required if the formation is recommended pursuant to the guidelines at § 271.705(b)(2). (Those guidelines are discussed *infra.*) Such information includes the types and extent of enhanced production techniques which are expected to be necessary to increase production from a well producing from the recommended tight formation, the estimated expenditures necessary for employing those techniques, the degree of increase in production to be expected from use of such techniques, and engineering and geological data to support that estimate. As previously mentioned, the Commission may request additional information.

B. Guidelines for Designating Tight Formations

The Notice of Proposed Rulemaking suggested the following guidelines:

(1) The formation must have an estimated average *in situ* gas permeability, throughout the pay section, of 0.03 millidarcy per foot or less;

(2) A well drilled into the formation must be expected to produce, with no production stimulation, an average of 200 Mcf per day or less;

(3) Production from such a well must be expected to be increased substantially after the completion of an appropriate enhanced production technique; and

(4) No field rules for development of the formation or portion thereof have been established by or requested of a jurisdictional agency.

The comments convinced the Commission to either change or eliminate each of these guidelines.

1. *The permeability standard.* An overwhelming majority of comments protested the permeability standard of 0.03 millidarcy as unreasonably low. Suggested permeability guidelines ranged from 0.05 millidarcy to 2 millidarcies. Some of the commenters suggested the permeability guideline should be tied to the depth of the formation or the pay thickness. Others insisted that permeabilities are so hard to measure that a permeability guideline should not be adopted.

During the course of meetings held with jurisdictional agencies some of the States expressed particular concern that the existence of a permeability guideline would effectively disqualify many areas which they feel should be subject to incentive pricing. They explained that the permeability of many tight formations is so variable that estimating the "average" permeability would be meaningless since permeability and productivity vary greatly from one location to the next. They also expressed concern that some formations with very low production capability would be excluded under the permeability guideline. Because of these difficulties, it was suggested the rule should focus on low production capability and should not include a specific permeability guideline.

The Commission recognizes the difficulties of adopting a permeability guideline. However, the objective of this rule is to identify and provide incentives for the development of tight formations, not to provide incentives to develop formations merely because they have low production rates. The problem presented by formations of extremely variable characteristics is certainly not evident in many tight formations. In fact, the permeability of many formations is reasonably uniform and estimations regarding average permeability may reasonably represent the permeability which will be encountered from one location to the next. Under these circumstances, a permeability limit may appropriately be imposed. If the formation's average permeability can be reasonably estimated by a jurisdictional agency and that permeability falls within the standard established in this rule, the Commission can rely on the jurisdictional agency's recommendation to a greater extent than if the average permeability could not reasonably be estimated. However, in order to respond to the various situations with maximum flexibility, the Commission has adopted alternative guidelines, differing in the permeability limit contained in each. The first incorporates a special permeability limit; the second does not, but provides for more extensive review of the recommendation.

The first alternative contains a permeability limit of 0.1 millidarcy, and oil and gas productivity limits. (See *infra.*) A permeability limit of an average of 0.1 millidarcy throughout the pay section has been adopted in the first set of guidelines because it would include most recognized tight formations.[1] It is also the lowest permeability which can be reasonably measured without engaging in highly expensive pressure build-up and drawdown tests. Data regarding matrix permeability alone will not be sufficient to qualify a formation,[2] because formations with very low matrix permeabilities may be economic to develop if fractures have developed naturally. Therefore, to fulfill the guideline containing the specific permeability limit, the formation's average effective or *in situ* permeability throughout the pay section must be expected to be 0.1 millidarcy, or less.

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[1] *See.* Department of Energy, *Enhanced Recovery of Unconventional Gas, The Program,* Volume II (of 3 Volumes), October, 1978, Lewin & Associates, pp. 1–20, contained in the Public File in Docket No. RM79–76.

[2] Matrix permeability is the permeability of the rock itself, disregarding any natural fractures or other factors that may affect average permeability throughout the pay section.

Permeability need not be proven on a well-by-well basis, but should be determined based on the jurisdictional agency's reasonable geological expectations regarding the formation. Such an expectation should be based on geological evaluations founded on the best information available.

None of the suggestions to tie the permeability limit to the depth of the formation or its pay thickness have been adopted. While the Commission recognizes that the depth of the formation affects the economics of developing a tight formation, that factor has been reflected in the production rate limit applicable under both alternative guidelines. (Discussed *infra.*) Adopting a ratio which reflects a permeability-pay thickness relationship would not substantially aid in the identification of tight formations.

With respect to permeability, the second alternative guideline requires only that the jurisdictional agency make an adequate showing that the incentive price is necessary for production of the formation because the formation is high-risk and high-cost and the formation has low permeability characteristics. It also contains the same oil and gas productivity limits as are applicable to the first alternative guideline.

The Commission notes that it will give greater deference to recommendations in which the jurisdictional agency is satisfied that the expected average permeability of the formation does not exceed 0.1 millidarcy. Recommendations regarding tight formations in which the average permeability cannot be reasonably estimated or the average permeability does not fall within the 0.1 guideline will be subject to more extensive review than those in which the specific permeability guideline is met. In this case, the Commission cannot be as confident that the recommended formation should be subject to incentive pricing and will thus engage in more extensive factual inquiry concerning the qualification of the formation as a designated tight formation.

2. *The gas productivity standard.* Both alternative guidelines incorporate a gas productivity standard. However, in response to the proposal, several of the commenters stated that the 200 Mcf or less per day production limitation was too low and that it should be adjusted upward to account for the greater risks and costs encountered in drilling deeper wells. Four commentors suggested formulas to calculate the production limit for any given depth. Although the formulas varied, all but one would have allowed the same general range of production per depth of the formation.

The Commission recognizes that costs of drilling and equipping gas wells do increase exponentially as well depths increase. The deeper wells must have much higher production rates in order to be economical. As a result, the Commission is convinced that the limitation on expected production rates should be tied to the depth of the formation. The formula adopted in this rule generally conforms to the range of production rates suggested by the commenters for various depths. It also closely parallels the exponent of increase in costs of drilling and equipment gas wells with depth, as demonstrated in the 1977 Joint Association Survey on drilling costs.[3]

The jurisdictional agency must reasonably expect that absent stimulation the wells completed in the recommended tight formation would not sustain production against atmospheric pressure on a daily basis in excess of the production rate determined in accordance with the following table:

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[3] American Petroleum Institute, February 1979 edition.

If the average depth to the top of the formation (in feet)		The maximum allowable production rate (in Mcf/day)
exceeds	but does not exceed	may not exceed
0	1,000	44
1,000	1,500	51
1,500	2,000	59
2,000	2,500	68
2,500	3,000	79
3,000	3,500	91
3,500	4,000	105
4,000	4,500	122
4,500	5,000	141
5,000	5,500	163
5,500	6,000	188
6,000	6,500	217
6,500	7,000	251
7,000	7,500	290
7,500	8,000	336
8,000	8,500	388
8,500	9,000	449
9,000	9,500	519
9,500	10,000	600
10,000	10,500	693
10,500	11,000	802
11,000	11,500	927
11,500	12,000	1,071
12,000	12,500	1,238
12,500	13,000	1,432
13,000	13,500	1,655
13,500	14,000	1,913
14,000	14,500	2,212
14,500 *	15,000	2,557

* Any completion locations deeper than 15,000 feet which qualify under this rule are deregulated pursuant to section 107 of the NGPA; therefore this rule is not applicable to those wells.

The table is derived from the following formula: [3]

$Q = 33e^{.29D(000)}$

Where:

Q = Production rate (Mcf/day)

D = The average depth to the top of the formation (in thousands of feet)

e = Base of natural logarithms (2.71828)

The comments also expressed concern that the productivity limit did not specify the time period in which the average flow rate is to be measured. The comments were concerned that many wells initially enjoy a high flow rate, but that the flow rate falls rapidly and drastically after the gas immediately surrounding the well bore is produced.

We do not believe it would be helpful to specify a time period during which the flow rate should be expected. The flow rate is to be based on what would be expected on a sustained basis against atmospheric pressure if no enhanced technique were applied. The jurisdictional agency itself should determine what expected flow rate would represent such sustained production.

It should also be emphasized that this guideline is not to be applied on a well-by-well basis. It applies to the production rate *expected* from untreated wells drilled in the recommended formation, and is to be based on geological evaluations founded on the best information available.

3. *Guidelines regarding increase of production after application of an enhanced recovery technique; and field rules.* The comments overwhelmingly objected to the adoption of the field rules guideline and the requirement that production should be expected to increase substantially after application of an appropriate enhanced production technique. These guidelines were suggested with the objectives of aiding in the identification of formations that (1) could not be economically developed without being subjected to expensive production techniques, and (2) are not already economic under presently available maximum lawful prices. Neither of these guidelines is being included in the interim rule.

As has been pointed out by the commenters, "substantially" increased production does not provide a meaningful guideline. The Commission does not feel it would be productive to quantify the standard, however, and has eliminated it as a guideline.

The field rules guideline is inappropriate for several reasons. First, many States have adopted state-wide field rules. All formations in those

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[3] See Appendix A for a graph. Appendix A is filed with the office of the Federal Register as part of the original document.

States would be disqualified if we were to retain the guideline. Second, field rules are often established for a whole formation even though only a specific area within the formation can be economically developed. The Commission does not intend to disqualify an entire formation if parts of that formation are tight and would not be developed without incentives. Those parts which are tight and would not be developed may qualify under this rule. Third, some States do not establish field rules even when formations have been extensively developed. Thus, the application of the field rules guideline to a given formation has proven to be irrelevant in determining whether a formation would be economic to develop without a special, incentive price and has been omitted in the interim rule.

The Commission's objectives still consist of identifying and including tight formations that could not be commercially developed absent application of enhanced production techniques, and excluding the types of development activities that could occur under the otherwise applicable maximum lawful prices. The Commission's original approach was to disqualify developmental (as opposed to exploratory) production from tight formations. Several alternative means of excluding such development were considered, including the proposed guidelines regarding enhanced recovery techniques and field rules, omitted from this rule. The Department of Energy (DOE) suggested disqualification of all wells located within one mile of the nearest marker well. Such a rule would have disqualified virtually all infill drilling. Additionally, under the proposal all behind-the-pipe gas was disqualified by the spud date requirement.

However, information contained in the comments indicated a need to extend incentives to developmental production. Many of the comments emphasized that much of the current development in tight formations is inadequate to produce the recoverable reserves. More importantly, they indicate that further development will not occur unless incentive prices are permitted for the first sales of such gas. Similarly, the comments emphasized that an incentive price is necessary to encourage the reworking of old wells so they will produce from tight formations which will be bypassed absent the availability of an incentive price. According to the comments a large amount of producible but economically unattractive reserves exist behind-the-pipe and in partially developed formations. Further development of these reserves may not occur under presently available prices because the costs of completing wells in the tight formations when considered with the low production rates, are too high. While they will not be produced at otherwise available prices, they could be the first tight formation gas on line and could supply significant volumes of tight formation gas until deregulation in 1985 under section 121, were an incentive extended to them.

Since such reserves are substantial, the public interest dictates that such production should not be discouraged. Developmental production of known reserves will not continue unless the benefits expected to be incurred as a result of such production are at least as attractive as the benefits expected to be incurred as a result of exploratory drilling. The risks and costs associated with exploratory and infill drilling are approximately the same since the locations of most tight, gas-bearing formations are already known, and the drilling and fracturing costs are equivalent for the two types of wells. While some differences may exist, the difference is not quantifiable given the Commission's current information base. It is obvious, however, that behind-the-pipe gas and gas obtained by deeper drilling require substantially fewer expenditures for drilling and pipeline hook-up facilities. Because the risks and costs associated with such production are less, the incentive need not be as great as the incentive for infill and exploratory drilling for new tight formation gas.

For purposes of the interim rule, the Commission has extended the interim ceiling of 150 percent of the section 103 maximum lawful price to "new tight formation gas", that is natural gas produced through new exploratory and new infill drilling. "New tight formation gas" is gas sold pursuant to a negotiated contract price, produced from a designated tight formation from a well the surface drilling of which began on or after July 16, 1979, and which either qualifies as section 102 gas or is produced from a section 103 well.

While new infill wells are not excluded from qualification under this rule, jurisdictional agencies should be sensitive to the fact that some portions of tight formations have been developed to such an extent as to indicate that the incentive maximum lawful price is not necessary to encourage full production of that portion of the formation. If the agency has information which indicates such portions can be developed without the incentive price, such portions should be excluded from the jurisdictional agency's recommendation.

Although it has not done so in the interim rule, the Commission is considering establishing a separate incentive price for qualifying behind-the-pipe production and gas produced from new deeper drilling, and requests comments on the proposal. Such gas is identified as "recompletion tight formation gas" and includes gas produced from a tight formation from a well that was not completed for production in the tight formation before July 16, 1979. (See discussion at pages 51 and 52 for a description of the Commission's proposal.)

4. *Production of crude oil.* The guidelines required that wells drilled into the recommended tight formation may not be expected to produce more than 5 barrels of crude oil per day. This requirement has been added to the guidelines to ensure that the gas is not produced in association with any more than a *de minimus* amount of oil. When gas is produced in association with oil, the presence of the oil, in itself, creates incentives for the development of the formation.

C. Production Qualifications

The Notice of Proposed Rulemaking contained the following well requirements:

(1) The surface drilling had to have begun on or after August 17, 1979,

(2) The well must qualify as a new, onshore production well,

(3) The well has been subject to an appropriate enhanced production technique, and

(4) The well must be drilled into a designated tight formation.

1. *Spud date requirement.* A spud date of August 17, 1979, was adopted in the proposal because the Statement on the Part of the Managers [6] indicates that the Commission's authority under section 107 (b) and (c)(5) is to be exercised in order to create incentives for development of gas reserves and therefore, is to be exercised in advance of such development.

Several commenters requested that an earlier spud date be allowed. Most requested that we adopt a date of February 19, 1977, since that is the cut-off date for new onshore production wells (section 103 wells), as well as new natural gas qualifying under section 102. The commenters argued that the February 19, 1977, spud date is the pivotal date in the wellhead pricing scheme under the NGPA. Other commenters suggested that the spud date be tied to the date the President first addressed Congress regarding the need to create incentives for development of gas-from tight formations. Still others argued that we should qualify old wells reentered and reworked after the spud date, or wells spudded before the spud date, but not subjected to an enhanced recovery technique at the designated formation at that time.

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[6] "This authority is intended by the conferees to be exercised in advance of drilling activity in order to create price incentives." Joint Explanatory Statement of the Committee on Conference Natural Gas Policy Act of 1978, Pub. L. 95–621, S. Rep. No. 95–1126, August 18, 1978, at page 88.

While the February 19, 1977, spud date is an important date under the NGPA, page 88 of the Statement on the Part of the Managers expresses Congress' intention that the pivotal date for section 107(c)(5) gas is the date the Commission exercises its authority under section 107(c)(5). The Commission has clearly been given the responsibility of encouraging increased development of high-cost or high-risk gas. We are not free to make available special prices for gas whose development was encouraged by previously available prices.

In the proposal we suggested a spud date which coincided with the date the Commission voted on the proposal so that drilling activity in tight formations would not be delayed until this rule was issued. However, in recognition of the fact that this rule gives effect to a policy initiated by the President's July 16th speech, the spud date for wells drilled into designated tight formations has been changed from August 17, 1979, to July 16, 1979.[7]

2. *Section 103 requirement.* A few commenters objected to the proposed requirement that tight formation gas must be produced through wells which qualify under section 103 of the NGPA. They objected to such a requirement because it would require them to satisfy the well-spacing and proration unit requirements contained in section 103. Some of the comments noted that some wells qualifying under section 102 might not qualify under section 103. Others noted that the requirements applicable to section 103 gas conflict with the proposed guideline that no field rules are applicable to the well. Because the Commission has dropped the field rule guideline, its conflict with section 103 is now irrelevant.

The requirement was proposed specifically for the purpose of ensuring that this rule does not encourage the drilling of unnecessary wells. When the proposal was issued, only production from new wells was envisioned as becoming eligible for incentive pricing. The incorporation of the requirements under section 103, which include well-spacing requirements, appeared to be a simple way of providing that no unnecessary wells qualify under this rule. It was not actually intended that gas qualifying under section 102 should not be eligible for the incentive price, as long as it meets the other requirements of this rule. Therefore, production qualifications for new tight formation gas have been modified to reflect that gas may either qualify under section 102 or be produced from a well which qualifies under section 103.

If the proposal to extend incentives to recompletion tight formation gas is adopted, fulfillment of State and Federal requirements regarding drilling and production will also be applied to such production. However, the requirement that the gas qualify under section 103 would not be applied to such gas.

3. *Enhanced production technique requirement.* The comments generally did not support the proposed requirement that all qualifying wells must have been subject to an appropriate enhanced production technique to be specified by the Commission for each designated tight formation. The commenters made the following objections to the requirement.

First, under the proposal an "appropriate" technique would have been a technique which the Commission had identified as requiring extraordinary expenditures and employed in order to substantially increase the production from the tight formation. The comments were concerned that limiting the appropriate techniques to those identified by the Commission would impede development of new technologies. They argued that the characteristics of each formation are so different that the rule must be flexible enough to allow experimentation and adoption of previously unrecognized techniques. Some of the comments suggested that the need for flexibility could be accommodated by allowing the jurisdictional agencies to identify appropriate techniques.

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[7] If the Commission adopts its new proposal to permit an incentive price for recompletion tight formation gas, certain tight formation gas produced from wells spudded before July 16, 1979, will also be eligible for an incentive price, albeit lower than that available for wells spudded after July 16, 1979.

Second, several comments argued that application of an appropriate technique should not be required at all. They argued that the incentive price should be made available simply to encourage more production of gas from tight formations. They argued that, if, by chance, a well were drilled next to a natural fracture, the producer should nevertheless receive the incentive price because he had assumed the risk of attempting to produce such gas. Several of the comments pointed out that if the guideline parameters were drawn narrowly enough and the fields were correctly identified there would be very few instances in which a producer would not have to engage in enhanced production techniques.

Finally, commenters emphasized that the enhanced production technique requirement would reduce the extent to which a producer could know in advance of drilling whether or not the well would qualify for the incentive price. If the well were drilled and no fracturing were required or it became apparent that no available technique could be used without damaging the productivity of the field, the producer would lose the incentive price. Commenters insisted that unless producers can be sure that the wells will qualify in advance of drilling, they will have little incentive to develop tight formations.

The Commission has reassessed the well requirement requiring application of an appropriate enhanced production technique based on the comments received. We have decided that application of an enhanced production technique should not be required in order for a well to qualify for the incentive price. However, because we continue to believe that formations which will not require extensive application of enhanced production techniques should not qualify under this rule, the guideline parameters are intended to eliminate all formations that will not require extensive application of enhanced production techniques for almost every well. We have attempted to draft the guidelines to eliminate most formations for which use of such techniques will not be necessary.

4. *Designated tight formation requirement.* As previously discussed, many comments were received concerning which formations should be identified as tight, and how such identification should be made. The proposed procedure has been substantially changed, because the Commission does not have the information needed to accurately identify qualifying tight formations. The Commission will rely on recommendations by jurisdictional agencies, and will approve or disapprove such recommendations after the public has been notified of such recommendation and has had the opportunity to comment.

The Commission has adopted this procedure so that it may fully utilize the information and expertise available to jurisdictional agencies without unduly delaying identification of tight formations. Once a formation has been designated, the incentive price may be applied retroactively with respect to all gas which meets the production qualifications of this rule.

5. *Negotiated contract price.* A requirement that the sale of the gas must be subject to a "negotiated contract price" has been added to the production qualifications. A "negotiated contract price" is defined as any price established by a contract which specifically refers to the Commission's incentive pricing authority under section 107 of the NGPA, or which contains a fixed rate or fixed escalator clause.

Pursuant to this requirement gas may not qualify as new tight formation gas unless the contract contains a fixed rate or escalator clause which would result in a price higher than the otherwise applicable maximum lawful price, or an escalator clause which specifically references the Commission's incentive pricing authority under section 107 of the NGPA. Moreover, the incentive price for gas which does qualify is the lesser of the negotiated contract price or 150 percent of the section 103 maximum lawful price.

This requirement serves the purpose of insuring that the incentive maximum lawful price is extended as an incentive for the production of additional new tight formation gas, rather than just as a windfall to the sellers. Contracts which do not presently contain a negotiated contract price may be amended. The Commission expects that purchasers will pay a higher price in return for increased production.

The Commission wishes to clarify the distinction between the requirement that there be a negotiated contract price and the Commission's position in Order No. 23, concerning the interpretation of area rate clauses. By requiring a negotiated contract price the Commission has imposed two limitations on the maximum lawful price. First, the maximum lawful price for the first sale of tight formation gas is determined by the otherwise applicable maximum lawful price unless the contract contains an effective negotiated contract price. Second, the maximum lawful price which may be collected if the contract contains an effective negotiated contract price may not exceed the lower of 150 percent of the section 103 price or the negotiated contract price. The Commission must limit the application of the incentive ceiling to those contracts which specifically refer to it (or to the extent permitted under a fixed rate or a fixed escalator clause) because its pricing authority is limited to setting incentive prices "necessary" to encourage additional production. However, the Commission emphasizes that the negotiated contract price requirement in no way constitutes an interpretation of an area rate clause.

The "negotiated contract price" requirement is reflected both in the definition of "new tight formation gas" in § 271.703(b)(3) and in the maximum lawful price established under § 271.702(b)(1). The Commission requests further comment on this provision.

D. The Incentive Pricing Ceiling

The response to the proposed basis for setting an incentive price for tight formations varied greatly. However, most commenters, including the Council on Wage and Price Stability and the Environmental Protection Agency (EPA) suggested that the ceiling should be tied to the price of imported Mexican or Canadian gas, or to the price of OPEC oil imports. The commenters argued that the proposed price ceiling did not reflect the value of such comparable, alternative fuels, especially given the rapid increase of imported oil prices in the last months of 1979. They would have us adopt a commodity value price-setting approach for section 107(b).

These commenters seem to argue that high cost gas is "worth" the Btu equivalent price of oil.[8] Therefore, according to this view, the section 107(b) price should be indexed to oil.

The incentive price ceiling originally proposed by the Commission in August 1979 was 150 percent of the section 103 maximum lawful price. One hundred and fifty percent of the section 103 price ($3.1035 per MMBtu) was at that time approximately equivalent to the then current price of Saudi Arabian benchmark crude oil, so that, when proposed, the Commission's determination of a "necessary" price would have been close to the price that would have been set under a commodity value basis. Events since that time in the oil market have led to 150 percent of the section 103 price being substantially below the "value" of gas as measured by its Btu equivalence with oil.

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[8] Since Mexican and Canadian gas are linked to oil, indexing section 107 prices to such imports would in effect link section 107 to oil prices.

It is not clear that the NGPA permits the Commission to adopt a commodity value approach. In attempting to set a price ceiling for tight formation gas, the Commission must adhere to the language of section 107(b) that mandates that any incentive price allowed by the Commission be "necessary to provide reasonable incentives for the production of such high-cost gas." The Statement on The Part of the Managers states that the prices are "not intended by the conferees to be cost-based in nature and do not require cost-justification."* This clarification implies that a section 107 price does not have to be "cost-based" or "cost-justified" in the conventional public utility pricing sense. However, the Statement provides no guidance about the nature of the difference between a "necessary" price and a cost-based or cost-justified price. Even so, both the specific use of the words "necessary" and "reasonable incentives" in the statute as well as the overall context of the statutory language seems to suggest that the Commission is not merely to index the price to some measure of value, such as the Btu price-equivalency of some other fuel, but is instead to set some price that is related to the particular needs of producers of the specific type of gas being accorded section 107 treatment.

The statutory standard appears to allow and even contemplate a price exceeding the price that would be allowed were the price required to be developed by traditional cost of service methodology as long as such a price were "necessary to create reasonable incentives for production" of the gas. Although Congress made a distinction between a cost-based price and a "necessary" price, logic implies a connection between a cost-of-service or cost of production price and "necessary" price because a "necessary" price clearly must at least cover costs.

None of the commenters who recommended a value-related price supported the recommendation with information suggesting that any ceiling higher than 150 percent of the section 103 price was "necessary". Nor do they provide a basis for distinguishing "reasonable" from "unreasonable incentives" for the production of tight formation gas. The Commission has no data or evidence that independently would permit a finding that a price equal to "value", i.e., the Btu price equivalence of oil, would be "necessary" and would not provide "unreasonable" incentives. Our drawing attention to these difficulties in the presentations is not mere bureaucratic fussiness on our part. In the absence of such a record, evidence or data support, the Commission has not been able to find the required basis for making the findings specified by Congress to support the suggested commodity value pricing.

Apart from the legal issues of statutory standards for setting section 107 prices, the Commission must deal with the broader and more worrisome issue of the inconsistency of commodity value ratemaking with the incentive price determinations made by the Congress in the NGPA. This is not just a matter of theoretical consistency; perverse incentives might be created by setting section 107 prices on a commodity value basis. The term "perverse incentive" is used advisedly because there is a potential that a commodity value section 107 rate would lead to less gas, on a nation-wide basis, compared with the production resulting from a price set on a different basis.

NGPA maximum lawful wellhead prices are not indexed to oil prices. Therefore, if commodity value ratemaking yielded a price for tight formation gas that was significantly higher than the price for other NGPA categories of gas, production activities in conventional formations might be diverted to tight formations. Drilling rigs used to explore and develop tight formations are the same as those used in regular formations and entrepreneurs will tend, presumably, to direct rigs to the formations that have the highest expected profit potential.[10] If we were to permit tight formation gas to be priced at its present commodity value (approximately $6.00 per MMBtu) and, assuming that the costs of drilling wells in tight formation are reasonably equivalent, then, even if the production rate for the tight formation well were only half of the production rate of the well in the conventional formation, revenues generated by the tight formation well would be significantly higher than that generated from the well in the conventional formation.

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*See page 88.

The Commission would not be as concerned about possible perverse incentives for developing tight formation gas if there were ample amounts of unused drilling and production equipment. Increased tight-formation drilling activity could be accommodated by rigs that would otherwise be idle if such spare capacity existed. But the demand for rotary rigs is at record levels. In August 1979, the supply of rigs totaled 3,182. This figure is 331 units, or 11.6 percent, greater than the number of rigs available in August 1978. Demand for drilling rigs and other production-related equipment is expected to increase significantly due not only to the incentive prices established by the NGPA but also to the scheduled phase-out of crude oil price controls. There is little, if any, spare drilling capacity, and it is far from clear that drilling and production equipment manufacturers will be able to fully meet the large and increasing demand for their products in the immediate future. The ability of drilling rig makers to expand capacity at more than 331 units per year remains to be demonstrated.

Because of these overall constraints on equipment supply relative to increasing demand, the Commission is concerned that unnecessary or excessive incentives for drilling and producing tight formation gas might have a negative impact on the development and production of other categories of natural gas, especially gas produced from new onshore development wells, as defined and priced under NGPA section 103.

If the average yield of a year's development efforts in tight formations were as great or greater than the yield from similar development efforts in conventional formations, it might be in the nation's interest to divert drilling activity in this manner. However, the Commission is unable to conclude at this time that the relative near-term production potential is as great or greater in tight formations than in conventional formations. The record in this proceeding suggests that some tight formation development wells that would become attractive for development if the gas were priced significantly higher than other NGPA prices, (as would result from setting prices on a commodity value basis) would have significantly lower yields than typical onshore production wells.

For these considerations, the Commission believes it is in the public interest to be cautious about setting incentive prices for tight formation gas on the basis of oil prices. Because we have no basis upon which to determine that such a ceiling is necessary and would not create perverse incentives and because the price ceiling as proposed in this docket provides a full 50 percent premium over the incentive that Congress provided for conventional development, we will adopt that ceiling until such time as information is available which suggests that a higher ceiling is "necessary" for new tight formation gas and will not have an adverse impact on total gas production. In the meantime, we invite the submission of more data. A study by the Tight Gas Reservoir Task Group of the NPC Committee on Unconventional Gas Sources may provide such information in the near future. While that study may not necessarily establish a basis for changing the price ceiling, we will use its availability to trigger reconsideration of the ceiling.

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[10] On the other hand, deep, high-cost natural gas, which is a deregulated category of gas under sections 107(c)(1) and 121, requires specialized drilling equipment and is usually produced at rates greatly in excess of conventional production rates.

The interim rule provides that the maximum lawful price for the first sale of new tight formation gas for which a negotiated contract price is applicable is the lesser of (1) the negotiated contract price, or (2) 150 percent of the maximum lawful price specified for section 103 gas. (For an explanation of "negotiated contract price" see pages 34 through 36.)

If the Commission decides that higher prices are appropriate and a higher maximum lawful price is adopted, it will be made effective as of July 16, 1979. In the meantime, the interim prices will be available to encourage production and the jurisdictional agencies may commence proceedings to designate tight formations. Because the Commission wishes to give as much price assurance as is possible to those who must make drilling decisions before a final ceiling is set, the Commission advises, as a general matter, that it will not lower the ceiling for new tight formation gas. However, there may be circumstances in which, because of disproportionate incentives for drilling infill wells, the Commission may find it necessary to reduce the incentive price for infill wells spudded after the effective date of the reduction.

The Commission requests that any comments specifically address the following issues: What ceiling is necessary to encourage production of new tight formation gas? Would too high a price divert production activities from conventional formations? Is the possibility of diversion grounds for establishing a lower price ceiling? Commenters are also requested to address the Commission's authority under section 107 or the NGPA to include tight formation gas as a deregulated category of gas, or to establish as a maximum lawful price, the price arrived at by negotiation between the purchaser and the seller.

The Commission also requests that comments include information regarding the price necessary to provide reasonable incentives for the production of recompletion tight formation gas. (See page 51, *infra*, for the specific proposal.) We propose a price ceiling equivalent to the maximum lawful price applicable to new, onshore production wells.

E. Environmental Impact

A letter was received from the EPA which suggested that the Commission should consider preparing a programmatic environmental impact statement pursuant to section 102(2)(c) of the National Environmental Policy Act of 1969.[11] After meeting with EPA and completing an environmental assessment, Staff has concluded that establishing an incentive price would not constitute a major Federal action significantly affecting the quality of the human environment. The Commission issued a notice to that effect on January 7, 1980,[12] and placed the assessment in the public files. To date, no comment has been received which contests the conclusion reached in the assessment.

The Commission will continue to evaluate the possible environmental effects of the tight formations program and will make a final determination as to environmental impact at such time as the jurisdictional agencies submit their recommendations for tight formations proposed to be designated under the rule. The information required of the jurisdictional agencies when they make their recommendations includes information regarding the identification and location of fresh water aquifers which may be affected by development of the formation.

F. Miscellaneous

1. *Deregulation.* The proposal specifically requested comment on the issue of deregulation of tight formation

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[11] 42 U.S.C. 4332(2)(c).

[12] See also section 601(b)(1)(E) regarding the affiliated entities limitation and the provisions of Title II applicable to incremental pricing of high-cost gas.

gas. The Commission was interested in soliciting comments as to whether section 101(b)(5) of the NGPA requires the eventual deregulation of tight formation gas which also qualifies as section 103 gas the price for which is deregulated in 1985 or 1987. Under section 101(b)(5) of the NGPA, "[i]f any natural gas qualifies under more than one provision * * * providing for any maximum lawful price or for any exemption from such a price with respect to any first sale of such natural gas, the provisions which could result in the highest price shall be applicable." Those that responded to this request argued that section 101(b)(5) compels deregulation of tight formation gas when that gas is finally determined to qualify under a deregulated category. The Commission agrees and notes with regard to the change in the interim rule that this argument applies equally to new tight formation gas which qualifies under section 102(c).

2. *Presently deregulated natural gas.* One commenter requested the Commission specifically exclude gas produced from coal seams from the tight formation category. The price for gas produced from coal seams has been deregulated pursuant to sections 107(c)(3) and 121 of the NGPA and the interim rules issued in Docket No. RM79-44 (45 FR 61950, October 29, 1979). Under section 101(b)(5), gas qualifying under one or more categories receives the highest maximum lawful price for which it is eligible, including a deregulated price, if applicable. Therefore, the Commission has no authority to impose the maximum lawful price for tight formation gas, or any other maximum lawful price on any category of gas, including coal seam gas, which has been deregulated.

3. *Definition of non-associated natural gas.* In the proposal the definition of "high-cost natural gas produced from tight formations" required the gas be "non-associated natural gas", meaning natural gas not produced in association with oil. One commenter pointed out that the term "non-associated natural gas" is defined only to the extent it is used in Subpart H of Part 271. A definition of "non-associated natural gas" has not been included in the interim rule; however, the guidelines provide that wells in a designated tight formation should not be expected to produce more than five barrels of crude oil per day. The definition of crude oil found in § 270.102(b)(5) applies to this rule and includes only mixtures of hydrocarbons that are liquid in the underground formations and remain liquid at atmospheric pressure.

4. *Coordination with the Natural Gas Act.* One commenter requested the Commission specifically state in the regulation that any interstate pipeline purchasing natural gas produced from tight formations will be able to roll such costs into its overall gas purchase costs and that such costs will be deemed just and reasonable pursuant to section 601(b) of the NGPA. Section 601(b)(1)(A)(i) states that any amount paid in any first sale of natural gas is "deemed to be just and reasonable" for purposes of sections 4 and 5 of the Natural Gas Act, so long as that amount does not exceed the applicable maximum lawful price for that gas. Further, section 601(c) provides for the passthrough of such just and reasonable prices paid by interstate pipelines for natural gas, "except to the extent that the Commission determines that the amount paid was excessive due to fraud, abuse, or similar grounds." [13] Any statement in these rules could do no more than restate the provisions of the NGPA, which govern these sales on any case. Therefore, we have denied the commenter's request, noting that for purposes of sections 4 and 5 of the Natural Gas Act, section 601(b) of the NGPA deems any amount paid in any first sale just and reasonable if such amount does not exceed the applicable maximum lawful price established under Title I of the NGPA.

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[13] See also section 601(b)(1)(E) regarding the affiliated entities limitation and the provisions of Title II applicable to incremental pricing of high-cost gas.

5. *Filing requirements.* Little comment was received on the proposed filing requirements. They have been changed to reflect the differences between the interim rule and the proposed rule.

VI. Description of the Interim Rule and Request for Further Comments

A. Summary of the Interim Rule

The interim rule establishes a special maximum lawful price for gas that qualifies as new tight formation gas. The price may not exceed the lesser of the negotiated contract price or 150 percent of the section 103 maximum lawful price. In other words, the price for new tight formation gas may not exceed its otherwise applicable maximum lawful price unless the contract specifically authorizes a higher rate under a fixed price or fixed escalator clause, or a pricing clause that specifically refers to the Commission's incentive pricing authority under section 107 of the NGPA. The price paid under such a contract may not exceed 150 percent of the section 103 maximum lawful price. The retroactive collection provisions at § 273.204(a) are applicable to tight formation gas. Such retroactive collection may apply to deliveries on or after July 16, 1979.

Gas qualifies as new tight formation gas if (1) it is either new natural gas or gas produced through a new onshore production well; (2) it is produced from a designated tight formation through a well the surface drilling of which began on or after July 16, 1979; and (3) a negotiated contract price is effective with respect to its sale.

Designated tight formations include those formations recommended by jurisdictional agencies and approved by the Commission. The Commission will approve any tight formation recommended by a jurisdictional agency if (1) the formation's estimated average *in situ* gas permeability throughout the pay section is not expected to exceed 0.1 millidarcy; (2) the stabilized production rate of wells completed for production in the formation, without stimulation, is not expected to exceed the rate set forth in the table which appears at § 271.705(b)(1)(ii); and (3) wells in the formation are not expected to produce more than 5 barrels of oil per day. The Commission will consider, and may approve recommendations to designate formations in which the average *in situ* gas permeability cannot be reasonably estimated or exceeds 0.1 millidarcy, so long as the stabilized production rate and crude oil production standards are met, and the jurisdictional agency demonstrates that the formation exhibits low permeability characteristics and, due to extraordinary risks or costs, the incentive rate permitted in this rule is necessary to provide reasonable incentive for the production of gas in the recommended formation.

Upon the receipt of a recommendation, including the information required in § 271.704(c) the Commission will publish in the Federal Register a notice of proposed rulemaking containing the recommendation. After review of oral and written comments on the proposal the Commission will issue a rule approving or disapproving the recommendation. (A list of designated tight formations will be included in the rules at a new § 271.706.)

A person seeking a determination that gas qualifies as new tight formation gas must submit information required at § 274.205(e).

The Commission has modified the provisions covering deep high-cost gas slightly, and intends to move them to part 272 at such time as the provisions for deregulated gas are issued as final rules.

B. Request for Further Comments

The Commission requests further comments and additional information on the maximum lawful price that should be permitted new tight formation gas and the legal and practical issues surrounding various alternatives, such as deregulating tight formation gas. Such comments should include information indicating what price is "necessary" to provide reasonable incentives for the production of such gas. Comments will be accepted until March 28, 1980, or

until such later date as the Commission may prescribe.

In addition, the Commission is considering establishing incentive prices for gas produced from designated tight formations which does not qualify as new tight formation gas but which is produced from wells which were not completed for production in the tight formation prior to July 16, 1979.[14] The following new category (and definition) is proposed:

§ 271.703 *Definitions.*

* * * * *

(c) "Recompletion tight formation gas" is natural gas:

(1) Which is produced from a designated tight formation through a well, the surface drilling of which was begun before July 16, 1979, if such well was not completed for production from such formation before July 16, 1979; and

(2) for the first sale of which a negotiated contract price is effective.

The Commission also proposes to permit a price ceiling based on the section 103 maximum lawful price with respect to "recompletion tight formation gas." The proposal would read as follows:

§ 271.702 *Maximum lawful prices.*

* * * * *

(b) *Tight formation gas.*

* * * * *

(2) *Recompletion tight formation gas.* The maximum lawful price, per MMBtu, for recompletion tight formation gas shall be the lesser of:

(i) The negotiated contract price; or

(ii) The maximum lawful price specified for Subpart C of Part 271 in Table I of § 271.101(a).

The Commission requests further comments on these proposals.

V. Public Procedures

Interested persons may submit comments by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, on or before March 28, 1980. Each person submitting a comment should indicate that the comments are being submitted in Docket No. RM79-76, and should give reasons including any supporting data for any recommendations. Comments should also indicate the name, title, mailing address, and telephone number of one person to whom communications concerning the proposal may be addressed. An original and 14 conformed copies should be filed with the Secretary of the Commission. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street NE., Washington, D.C. 20426, during regular business hours.

A date and location of further hearings on this rulemaking may be announced in the near future. The proposed regulations will not be promulgated as final regulations until the Commission has had an opportunity to receive oral presentation of relevant data, views and arguments.

VII. Effective Date

This rule was originally proposed for comment on August 29, 1979 (44 FR 52255, September 7, 1979). Informal public hearings were held in Washington, D.C., on September 24, 1979, and in Denver, Colorado, on September 27, 1979. Written comments were accepted until January 22, 1980.

By this process the Commission has complied with the provisions of section 502(b) of the NGPA which requires that "[t]o the maximum extent practicable," an opportunity for the oral presentation of data, views, and arguments be afforded for certain regulation under the NGPA. The provisions contained in this order rest upon consideration given to the information received during the above-described notice, comment, and hearing process.

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[14] This proposal has also been noticed in a Notice of Proposed Rulemaking, published in this issue of Federal Register.

These rules shall become effective as interim regulations on March 21, 1980.

(Department of Energy Organization Act, (42 U.S.C. 7101, *et seq.*); E.O. 12009, 42 FR 46267; Natural Gas Policy Act of 1978, (15 U.S.C. 3301–3432))

In consideration of the foregoing, Subpart G of Part 271, Subpart B of Part 273, and Subpart B of Part 274, of Subchapter H, Chapter I, Title 18, Code of Federal Regulations, are amended as set forth below, effective as interim rules on March 21, 1980.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,131]

45 F. R. 15523 (March 11, 1980);
45 F. R. 45905 (July 8, 1980)

18 CFR Part 274

[Docket No. RM80-15; Order No. 65-A]

Minimum Filing Requirements For Applications to Jurisdictional Agencies for Determinations of Eligibility for Various Categories of Natural Gas; Order Granting in Part and Denying in Part Rehearing of Order No. 65

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Order Grenting In Part and Denying In Part.

SUMMARY: This Order grants in part as well as denies in part two applications for rehearing of Order No. 65 (Docket No. RM80-15, 45 FR 3890, January 21, 1980). Order No. 65 provided final regulations for minimum filing requirements for applications to jurisdictional agencies for determinations of eligibility for various categories of natural gas. This order responds to the petitions for rehearing of Order No. 65 by clarifying that a search of jurisdictional agency records does not necessitate a search of all records which contain similar data; clarifying that an applicant may satisfy his search requirements by using data compiled by professional services; clarifying that the applicant may rely on true and correct copies of production reports in the companies files and filed with the jurisdictional agency for purposes of § 274.206(a)(4)(i).

In addition, this order amends § 274.206(a)(9) to require the applicant seeking a stripper well determination to submit production reports for each completion location for (1) the 90-day production period, and (2) the 12-month production period establishing the maximum efficient rate of flow (if applicable).

EFFECTIVE DATE: February 29, 1980.

FOR FURTHER INFORMATION CONTACT:

Clarence Burris, Office of General Counsel, Federal Energy Regulatory Commission, Room 8106–A, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357–8161,

or

Thomas P. Gross, Office of the General Counsel, Federal Energy Regulatory Commission, Room 4102–B, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357–8026.

February 29, 1980.

On January 4, 1980, the Commission in Order No. 65 (45 FR 3890, January 21, 1980) issued Final Regulations (effective February 4, 1980) for a minimum filing requirements for applications to jurisdictional agencies for determinations of elibility for varous categóries of natural gas. The Commission has received two timely petitions for rehearing of Order No. 65 from Tenneco Oil Company (Tenneco) and from Pennzoil Company, General American Oil Company of Texas, and Texasgulf, Inc. (collectively Petitioners).

In their petitions for rehearing, Tenneco and Petitioners object to certain aspects of the record requirements imposed in the final regulations promulgated in Order No. 65. Sections 274.202, 274.203, and 274.206 establish the filing requirements for new natural gas, from new onshore production wells and stripper well gas, respectively. These sections (specifically §§ 274.202(e), 274.203(f) and 274.206(a)(10)) require the applicant to state under oath that he has made, or caused to be made a diligent search of all records which are reasonably available and contain information relevant to the determination of eligibility. The applicant is further required to describe, under oath the search made, the records reviewed, the location of the records, and a description of any records which the applicant believes may contain information relevant to the determination but which he has determined are not reasonably available to him. Petitioners state that the document search reporting requirements in these sections are vague, unreasonable, onerous, and unnecessary. Petitioners request the Commission to precisely define what information is required and to limit the search and reporting requirements to information that is absolutely necessary.

The Commission believes that the document search and reporting requirements under these sections of the regulations are necessary and that the search requirements are sufficiently narrow to restrict the search to relevant information. These regulations limit the search requirements to records which are reasonably available and which contain information relevant to the determination of eligibility. These requirements are necessary to insure that the applicant has discovered and presented to the jurisdictional agency all information which supports the application, as well as information which does not support the application. Moreover, it is impossible to designate in the regulations the specific documents which must be searched because these documents will vary with the circumstances and history of each well.

In its petition for rehearing Tenneco requested that the Commission clarify that the record search requirements imposed in Order No. 65 do not, in all instances, necessitate a search of jurisdictional agency records. Tenneco states that it would be an extremely burdensome task to search agency records in every case. Accordingly, Tenneco requests that the search requirements be clarified in the following manner.

First, Tenneco requests that the Commission clarify that a search of jurisdictional agency records does not necessitate a search of all records which contain similar data. For example, Tenneco states that data obtained through a search of production records may eliminate the necessity to search tax, royalty or other records containing similar data.

The Commission agrees that a search of *all* jurisdictional agency records containing similar data is not necessary. The applicant need not search each type of record; instead, the applicant should initially determine which jurisdictional agency records provide the most significant data and then conduct the subsequent record search accordingly. If the records searched do not provide the information sought, the applicant must, of course, conduct a search of additional records.

Second, Tenneco states that the Commission should eliminate a search of jurisdictional agency records where the information available in those records is obtainable through a more accessible and convenient source. In those cases where the applicant's records contain the same information as the jurisdictional agency's records, Tenneco states that the search of the jurisdictional agency's records would not reveal any additional information. In other cases, Tenneco states that applicants should be allowed to rely on information compiled from public records by certain associations and professional services.[1]

The Commission believes that an applicant should bear the responsibility of searching company and jurisdictional agency records which are reasonably available and which may contain information which is reasonably related to the determination of eligibility. In some cases, the records maintained by the jurisdictional agency are copies of the company's records which were submitted by the company itself, and contain no additional information not already available to the company. In such cases, the Commission does not expect the applicant to search the jurisdictional agency's records, as long as the applicant has no reason to believe that the jurisdictional agency's records contain relevant information in addition to copies of the applicant's own records. However, a search of the jurisdictional agency's records may be necessary for the applicant to verify that the jurisdictional agency's records are in fact identical to the company's records.

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[1] *E.g.*, Dwight's Energydata, Inc.; Herndon Map Service; Petroleum Information Corporation; R. W. Bryan & Company; Tobin Research, Inc.; and Mason Map Service.

The Commission recognizes that in many cases the applicant may satisfy his search requirements by relying on data compiled by professional services, provided that the applicant has a reasonable basis for concluding that such service provides accurate, complete, and precise information. If the applicant relies on such services, he must identify the service he has used and specify the particular location of such information by volume and page number, or other appropriate means. In any case, the applicant retains responsibility for submitting accurate and complete information in his application.

Third, Tenneco seeks clarification of § 274.206(a)(4)(i) which requires the filing of copies of production records, or if so permitted by the jurisdictional agency, summaries of such records. Tenneco states that the production reports filed with the jurisdictional agency may be copies of production reports in the company's files, and requests that the Commission clarify that an applicant may rely on true and correct copies of reports filed with the jurisdictional agency.

Section 274.206 establishes the filing requirements for stripper well applications. Section 274.206(a)(4)(i) requires the applicant to submit production records for the 12 months ending on the last day of the 90-day production period upon which the application is based. Certain other records may be used if the production records are not available. In either case, the applicant may submit summaries of such records if so permitted by the jurisdictional agency. The Commission agrees that the applicant may satisfy the filing requirement under § 274.206(a)(4)(i) by using copies of production reports in the company's files if such copies are true and correct copies of the reports on file with the jurisdictional agency.

Sections 274.203(e)(1), 274.206(a)(3), and 274.206(a)(9) require the applicant to submit test results for wells drilled into reservoirs on old OCS leases prior to July 27, 1976, maximum efficient rate of flow test results for stripper wells, and production records for each completion location penetrated by a stripper well, respectively. Petitioners request that these sections be amended so as to require the applicant to submit only sworn affidavits as to the contents of these tests and records, and not the actual test results and records themselves. The Commission believes that the actual test results and records should be available to the jurisdictional agency and the Commission so that such information and the conclusions drawn by the applicant as to the meaning of such information may be verified. Therefore, applicants are required to submit copies of the actual test results and records.

Section 274.206(a)(9) requires an applicant seeking a determination of eligibility for a stripper well to submit production records for each completion location penetrated by the well bore if the well is a multiple completion well. These records are necessary to verify that the total production from all completion locations does not exceed an average of 60 Mcf per day for the 90 day qualifying period and to provide information on the 12 month period on which the maximum efficient rate of flow is based, if applicable. Petitioners state, however, that this regulation requires the applicant to submit production records for the well's entire production history, irrespective of current production. Because the relevant period of production is the 90 day

qualifying period and the 12 month period on which the maximum efficient rate of flow is based, if applicable, production records should be submitted only for those periods. Therefore, § 274.206(a)(9) is being amended to require the applicant to submit the production records only for the 90 day qualifying period and for the 12 month period on which the maximum efficient rate of flow is based, if applicable. This amendment relieves a filing requirement and is thus being made effective immediately with regard to jurisdictional agency determinations which have not yet become final under § 275.202 as of the day before the date of issuance of this order.

The Commission orders

(A) To the extent not granted above, the petitions for rehearing of Order No. 65 are denied.

(B) Order No. 65 is clarified, as set forth above; and

(C) To the extent granted above, the petitions for rehearing of Order No. 65 are granted and the final regulations amended accordingly, effective as set forth above.

(Natural Gas Policy Act of 1978, (15 U.S.C. 3301 *et seq.*), Department of Energy Organization Act, (42 U.S.C. 7101 *et seq.*), E.O. 12009, 42 FR 46267)

In consideration of the foregoing, Subpart B of Part 274 Chapter I, of Title 18, Code of Federal Regulations, is amended as set forth below, effective immediately for all jurisdictional agency determinations which have not yet become final under § 275.202 as of February 28, 1980. These rules, as amended, are final regulations with the exception of paragraphs (b), (c) and (d) of § 274.205 which will remain as interim rules until further notice.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,132]

45 F. R. 16171 (March 13, 1980)

18 CFR Part 271

[Docket No. RM80-19; Order No. 64]

Ceiling Prices; Natural Gas Committed or Dedicated to Interstate Commerce; Order Denying Applications for Rehearing and Stay and Amending Regulations

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Order Denying Rehearing and Stay and Amending Regulations.

SUMMARY: On January 3, 1980, the Commission issued Order No. 64, 45 FR 5685 (Jan. 24, 1980), which promulgated final regulations implementing the pricing provisions of sections 104 and 106(a) of the Natural Gas Policy Act of 1978 (NGPA). Sections 104 and 106(a) address first sales of natural gas committed or dedicated to interstate commerce on November 8, 1978.

Five applications for rehearing of Order No. 64 were filed. This order denies rehearing on all issues raised in these applications. It also amends Subpart D of Part 271 to provide for pricing of production from reservoirs penetrated for the first time through deeper drilling in an existing well, and to provide that a seller of interstate rollover contract gas may receive the higher of the maximum lawful price applicable to the expiring contract or the 54 cent rollover rate established in section 106(a)(2) of the NGPA.

EFFECTIVE DATE: February 27, 1980.

FOR FURTHER INFORMATION CONTACT: Carol Lane, Federal Energy Regulatory Commission, Office of the General Counsel, Room 8100-k, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-9124.

February 27, 1980.

On January 3, 1980, the Federal Energy Regulatory Commission (Commission) issued Order No. 64.[1] By that order, the Commission established final regulations implementing sections 104 and 106(a) of the Natural Gas Policy Act of 1978 (NGPA).[2] Those sections prescribe ceiling prices for first sales of natural gas committed or dedicated to interstate commerce on November 8, 1978 and for which a just and reasonable rate under the Natural Gas Act (NGA)[3] was in effect on that date.

The Commission received five applications for the rehearing of Order No. 64. Applications were timely filed on behalf of the Columbia Gas Development Corporation, Energy Ventures, Inc. Coleve, and the Forest Oil Corporation (Columbia) (filed January 29, 1980); Pennzoil Oil and Gas Inc. and the Pogo Producing Company (POGI) (filed February 1, 1980); Undersigned Producers (Undersigned)[4] (filed February 1, 1980); the Amoco Producing Company (Amoco) (filed February 1, 1980); and the Texas Gas Exploration Corporation (TGEC) (filed February 4, 1980). TGEC also filed an application for stay of Order No. 64. These applications, taken collectively, contend that the Commission erred in Order No. 64 by: (1) Failing to apply the NGPA monthly inflation adjustment factor to rates prescribed by the Commission under the optional procedure of § 2.75 of its regulations; (2) prescribing a nationwide or areawide rate ceiling for natural gas sales made during the pendency of Commission review of an application under optional procedure; and (3) by its definition of the application of a minimum rate for natural gas sales.

By this Order, the Commission responds to these contentions and, for reasons given below, rejects them and applicants' prayers for reconsideration of Order No. 64. In addition, we take this opportunity to clarify and amend the regulations of Subpart D of Part 271 to provide for production from reservoirs penetrated for the first time through deeper drilling in an existing well; and to make it clear that, as prescribed by section 106(a) of the NGPA, a seller may receive the higher of the ceiling rate applicable on the date of rollover or the 54 cent rate of section 106(a)(2).

A. Applications for Rehearing

1. *Optional Certificate Ceiling Rate.* Under the final regulations of Subpart D, those who sell natural gas subject to a certificate issued under the Commission's optional procedure of § 2.75 may not collect a price which is increased by the inflation adjustment of the NGPA.[5] Applications submitted by Columbia, POGI, Undersigned, and TGEC argue that to deny the addition of the NGPA monthly inflation adjustment to the price of optionally certificated gas is error. We disagree.

Taken together, applicants argue as follows. First, in that a rate established under the optional procedure is a just and reasonable rate established under the NGA, it falls squarely within the provisions of section 104 of the NGPA to the extent that it was in effect on November 8, 1978. Second, section 104 makes no distinction as to how a rate was set under the NGA; instead it states that its pricing provisions "shall apply to any first sale" of natural gas committed or dedicated to interstate commerce on November 8, 1978, for which a just and reasonable rate under the NGA was in effect on that date. Third, the waiver of the right to seek future rate increases under section 4 of the NGA made by those accepting a certificate under the optional procedure can be given no effect under the Commission's rate-setting authority under the NGPA; the waiver was only to seek future NGA rate increases and cannot be made to reach to rate increases statutorily mandated by the NGPA. Finally, the certificate pricing provisions issued under the NGA were statutorily revised to give effect to the NGPA ceiling prices; that is, the NGPA supersedes inconsistent provisions of the NGA and Commission regulations issued thereunder.[6]

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[1] Order No. 64, "Order Reissuing Part 271, Subpart D of the Commission's Regulations as Final Regulations", Docket No. RM80-19 (issued Jan. 3, 1980) 45 FR 1862 (Jan. 9, 1980), *as corrected*, Erratum Notice (issued Jan. 17, 1980) 45 FR 5685 (Jan. 24, 1980).

[2] 15 U.S.C. 3314, 3316.

[3] 15 U.S.C. 717 *et seq.*

[4] This application was made on behalf of the Tenneco Oil Co., the Pennzoil Co., the Pogo Producing Co., the Pennzoil Producing Co., Pennzoil Oil and Gas, Inc., the Texaco Oil Co., the Texas Production Co., Pinto, Inc., Ecee, Inc.

[5] Order No. 64, note 1 *supra* at 15–26; *see also* 18 CFR 271.402(c).

The arguments of applicants miss the point. The question is not whether the ceiling price of section 104 applies to sales of natural gas made under optional pricing certificates. Quite clearly, it does. Nor is the question one of the Commission's rate-setting authority under the NGA as opposed to (or superseded by) its rate-setting authority under the NGPA. The question is the scope of the waiver made by those who accepted certificates issued under the optional rate procedure and its continued applicability.

Section 4(d) of the NGA provides, *inter alia*, that before one may change a rate schedule, notice and filing of that change must be made to the Commission. Thus, any seller must seek rate increases under that section. What optional procedure sellers have waived is the right to file for rate increases. Absent such a filing, the new rate cannot be charged. Therefore, arguments that the waiver of the optional procedure goes only to NGA rate increases and not to NGPA rate increases, or that the waiver is a regulation going to the rate-setting authority of the Commission are incorrect. The waiver goes to the right to file for any future rate increase.

In determining whether the provisions of section 4(d) of the NGA applies, the Commission is guided by section 601 of the NGPA. That section rather specifically sets forth the jurisdiction of the Commission under the NGA given the NGPA. It does so by exception. Section 601(a)(1)(B) of the NGPA exempts certain gas (that determined to qualify under sections 102(c), 103(c) and 107(c) (1) to (4)) from Commission regulation under the NGA. Committed or dedicated gas which does not fall within those provisions remains subject to the Commission's non-price regulatory requirements of the NGA and the Commission's rules and regulations issued thereunder. Therefore, the requirement of section 4(d) of the NGA respecting the condition that one must file for a rate increase applies to sales of natural gas made under a certificate granted through the optional procedure, unless the gas is exempted from Commission regulation under section 601(a)(1)(B).

It is incorrect to contend, as do some of the applicants, that the NGPA worked a revision to all certificates issued under the NGA so as to give effect to NGPA prices. The NGPA revised the price-setting mechanisms of the NGA and Commission regulations issued thereunder. This is the substance of the Commission's issuances cited by applicants.[7] However, it did not amend the non-price regulatory requirements of the NGA save as specifically described under section 601. Therefore, arguments that the Commission misused its authority under section 601 of the NGPA or that it has voiced inconsistent views respecting the impact of the NGPA on the NGA are misplaced.

Arguments that the Commission's failure to permit optional certificate holders to increase their sales price by the monthly inflation factor of the NGPA runs counter to public policy and legislative intent must likewise be rejected. Given the provisions of section 601 of the NGPA, we believe that the Congress intended the filing provisions of section 4(c) to remain in effect for this type of gas sale.[8] In that holders of certificates granted under an optional proceeding have waived the right to file for a rate increase, to permit them to collect the higher rate applicable under the NGPA (higher by virtue of the monthly inflation adjustment), would be to disregard the law.

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[6] In support of this last argument, several of the applicants cited to issuances of this Commission (for example, to Appalachian Exploration and Development Inc. *et al.*, Docket Nos. CI79-590 *et al.* (issued Dec. 1, 1978); Pennzoil Co., Gas Rate Schedule No. 10 (issued Nov. 19, 1978); Natural Gas Policy Act of 1978: Interim Regulations, Docket No. RM79-3 at 9 (issued Dec. 1, 1978); and Order 23, "Order Adopting Final Regulations Amending and Clarifying Regulations Under the Natural Gas Policy Act and the Natural Gas Act," Docket No. RM79-22, issued March 13, 1979, for the proposition that we have recognized that all certificate pricing provisions issued under the NGA were statutorily revised to give effect to the provisions of the NGPA. The citations were to discussions of the Commission that the NGPA had superseded the NGA and the rules and regulations issued under that Act. As discussed more fully in the body of this order these citations are inapposite.

[7] *See* note 6 *supra*.

An argument was made that the Commission's failure to permit the inflation increase to optional certificate sales while permitting it to other sellers was arbitrary because it results in the NGPA overriding some certificate conditions and not others. In support of this argument it was claimed that certificates covering sales of gas from post-January 1, 1975, wells precluded sellers from applying for higher prices (except special relief) than the § 2.56a[9] prices until such time as the Commission established higher prices pursuant to its 1977–78 biennial rate review. It was further pointed out that, although a 1977–78 rate was never established, the Commission nevertheless permitted those certificate holders to file for and collect the section 104 price increases.

A distinction may be made between different types of certificate conditions, and we believe it is entirely proper to make such a distinction here. The general prohibition against applying for higher prices than those specified in § 2.56a was conditioned upon future rate-setting proceedings. Once higher prices had been established by the NGPA (which supplanted the 1977–78 biennial rate review) the condition was removed. In contrast, the prohibition against applying for higher prices under optional procedure certificates was not conditional; it was final. No future establishment of higher prices would permit certificate holders to apply for those prices.

In Order No. 64, we stated that where section 601(a)(1)(B) of the NGPA does not act to exempt optional procedure gas from NGA regulation, we will entertain petitions from certificate holders to amend the certificate so as to remove the waiver conditions. One applicant asserts that, given the views expressed in Order No. 64 that holders of optional certificates should not be given the advantage of first, a higher NGA rate and then the NGPA rate, we have prejudged such petitions and will not grant them. This is not so. Petitions will be considered, and they will be considered on their merits.

Some applicants point out that the effect of Order No. 64 to bar optional certificate holders from collecting an inflation-adjusted rate is to disallow collection of the "new natural gas" ceiling price prescribed by section 102(d) for gas produced from a new reservoir on the Outer Continental Shelf when such reservoir is in a block covered by an optional procedure certificate. (This result properly follows because section 102(d) is not exempted from NGA regulation under the provisions of section 601 of the NGPA.)[10] They contend that sellers of such gas are in fact entitled to collect the section 102(d) price by operation of section 101(b)(5) of the NGPA. Section 101(b)(5) provides that if gas qualifies under more than one NGPA pricing provision, the provision which could result in the highest price is applicable.

The proper response to this argument is the same as that given to those seeking an increase of rates under section 104 of the NGPA for optionally-certificated sales. The point is not whether the gas qualifies for the higher NGPA price, but whether one may collect that higher price. As with natural gas priced under section 104, a holder of an optional certificate whose gas sales qualify for the section 102(d) price is precluded under the terms of his certificate from filing under section 4(d) of the NGA to collect the higher price.

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[8] See Order Nos. 15 and 15–A, "Amendments to the Commission's Regulations Relating to Independent Producer Filing Requirements," Docket No. RM79-4, issued Nov. 17, 1978, and Dec. 28, 1978, respectively; Order No. 25, "Amendments to the Commission's Regulations Relating to Independent Producer Filing Requirements," Docket No. RM79-31, issued March 27, 1979.

[9] The prices codified in § 2.56a reflect rates set by the Commission in its 1975–1976 bienial rate review.

[10] In addition, optional procedure gas which qualifies under section 108(b) or section 107(c)(5) remains subject to the conditions of the NGA certificate.

Applicants also contend that we erred in providing that the proper ceiling price for sales of natural gas made under the provisions of § 2.75(o) respecting collections during the pendency of optional certificate determinations should be the applicable nationwide or areawide rates set under the NGA. (Order No. 64, note 1 *supra* at 26.) They object to references in Order No. 64 to an order issued on December 1, 1978,[11] in which the Commission stipulated that sellers awaiting action on their optional procedure applications were limited to collection of the applicable NGPA maximum lawful prices. This issue has been raised in petitions for rehearing of that order, and that rehearing was granted.[12] The Commission expects to issue the order on rehearing shortly after rules governing special relief are promulgated in Docket No. RM79-67. Accordingly, we will not address this aspect of optional procedure pricing in the context of Order No. 64.

Finally, in their application for rehearing of Order No. 64, POGI raised arguments pertaining to the interpretation of particular waiver conditions contained in optional certificates granted their predecessor under an optional proceeding. That case is now pending before the Commission;[13] and we will address those arguments in the context of that case.

2. *Minimum Rate Gas.* Amoco asserts that the Commission erred in promulgating § 271.402(b)(9), because that section permits the minimum rate to be collected only for gas from wells spudded prior to January 1, 1973. Amoco contends that under Opinion No. 749,[14] which established the most recent minimum rate, gas qualified for the minimum rate on a contract basis, not a well vintage basis. Accordingly, they assert, *all* gas sold under low-rate contracts is entitled to the minimum rate under Opinion No. 749, even if it is produced from a well spudded after January 1, 1973. Furthermore, Amoco suggests that this policy should be carried over into the NGPA regulations.

We believe that Amoco has misunderstood Opinion No. 749. That opinion, as its title indicates, established "Just and Reasonable Rates for Sales of Natural Gas From Wells Commenced Prior to January 1, 1973." The regulations promulgated in that order added a new § 2.56b to our existing rules entitled "National Rates for Sales of Natural Gas From *Wells Commenced Prior to January 1, 1973* (emphasis added). Under § 2.56b(b), a minimum rate of 18 cents was established. When the Commission later established national rates for gas from wells commenced *after* January 1, 1973 (Opinion Nos. 699-H and 770-A), it did not establish a minimum rate for gas from such wells. Accordingly, our NGA regulations on minimum rate gas apply only to gas from wells commenced prior to January 1, 1973. Order No. 64 simply carried forward these NGA regulations, adding an NGPA inflation adjustment to the minimum rate. Accordingly, our policy on minimum rate gas has not changed. Amoco has simply misinterpreted the existing NGA regulations.[15]

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[11] "Order with Respect to Pending Optional Procedure Cases" (Docket No. CI76-590, *et al.*) (issued December 1, 1978).

[12] Order Granting Rehearing for Purposes of Further Consideration, Docket No. CI76-590, et al. (issued Feb. 1, 1979).

[13] Docket No. CI73-477 and Docket No. CI78-81.

[14] Opinion No. 749, "Just and Reasonable National Rates for Sales of Natural Gas From Wells Commenced Prior to January 1, 1973", Docket No. R-478 (issued Dec. 31, 1975).

B. Regulatory Changes

1. *Deeper Drilling.* The Commission has received several inquiries on the FERC Hot Line pertaining to our definition of "Post-1974 Gas." Section 271.402(b)(2) defines such gas as that "produced from a well the surface drilling of which commenced on or after January 1, 1975." Callers have asked whether gas from a well spudded before January 1, 1975, would qualify as "Post-1974" gas if the well were drilled deeper into a new reservoir after January 1, 1975. These callers have pointed out that in Opinion No. 770-A,[16] the Commission stated:

> Production from reservoirs penetrated for the first time through deeper drilling[17] in an existing well is eligible for the same rate as if the deeper drilling constituted the commencement of such well.

In that the policies set forth in our area and national rate opinions are carried over into our regulations under the NGPA, gas from a reservoir penetrated for the first time through deeper drilling after January 1, 1975, in a well spudded prior to January 1, 1975, does qualify as "Post-1974" gas. Similarly, gas from a reservoir penentrated for the first time through deeper drilling after January 1, 1973, and before January 1, 1975, in a well spudded prior to January 1, 1973, qualifies as "1973-74 biennium gas." We are amending § 271.402(c) to set forth this policy as part of our regulations.

2. *Rollover ceiling rate.* Order No. 64 did not expressly provide that, when a contract rolls over under section 106(a) of the NGPA, the seller may receive the higher of the price applicable on the date of rollover or the 54 cent rate prescribed under section 106(a). This rollover pricing option is specified in both the statute and the Statement of Managers, which explains that "* * * if the just and reasonable rate applicable to the expiring contract was greater than the price that represents 54 cents per million Btu's escalated with inflation until the time of rollover, the new ceiling price is based upon the just and reasonable rate applicable to the expiring contract." S. Rep. No. 95-1126, 95th Cong., 2d Sess. 85 (1978).

The regulations are amended in §§ 271.101 and 271.402(c) to provide for this statutory alternative.

The Commission orders

For the reasons given above, the applications for rehearing and stay of Order No. 64 filed by the parties listed on pages 1 and 2 of this order are denied, and Order No. 64 is amended as set forth below.

Because the amendments give effect to statutory mandates and because they respond to issues raised during the pending of this rulemaking, we find that no further public procedure is necessary prior to their implementation. We further find, and for the same reasons, that the amendments should be made effective immediately.

By the Commission. Commissioner Sheldon voted present.

Kenneth F. Plumb,
Secretary.

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[15] In Opinion No. 749, the Federal Power Commission was concerned with pricing for wells commenced prior to January 1, 1973. It may not have contemplated a situation such as that described by Amoco, where all wells on a lease dedicated before January 1, 1973, are subject to a low fixed-rate contract, regardless of when they were drilled. As a result, wells drilled on this lease before January 1, 1973, are eligible for the minimum rate, but those drilled after January 1, 1973, are limited to a contract rate lower than the minimum rate. This Commission is not aware of this question being raised before. Amoco, and others who may be similarly situated, may file a petition asking the Commission to undertake a hearing under Section 5 of the NGA to determine whether the rate for gas from these wells is unjust, unreasonable, unduly discriminatory or preferential.

[16] Opinion No. 770-A, "National Rates for Jurisdictional Sales of Natural Gas Dedicated to Interstate Commerce on or after January 1, 1973, for the Period January 1, 1975, to December 31, 1976", Docket No. RM75-14 at 162 (issued Nov. 5, 1976).

[17] Deeper drilling is defined as drilling after the first completion and production in a well bore has been performed (*see* Opinion No. 770-A, note 16 *supra* at 162), or drilling below an uncompleted, nonproductive horizon where the initial well bore was plugged and abandoned (*see Imperial Oil Company, et al.*, Docket No. RI77-47, issued April 28, 1977).

[¶ 30,133]

45 F. R. 17129 (March 18, 1980)

18 CFR Part 275
[Docket No. RM79-3]

Final Part 275 Regulations Under the Natural Gas Policy Act of 1978

AGENCY: Federal Energy Regulatory Commission.

ACTION: Order on Rehearing of Order No. 34.

SUMMARY: On June 14, 1979 (44 FR 34475), Order No. 34 was issued in Docket No. RM79-3 by the Federal Energy Regulatory Commission (Commission). Order No. 34 issued final regulations in Part 275 of the Commission's regulations. Part 275 deals with Commission review of jurisdictional agency determinations regarding the appropriate classification of natural gas under Natural Gas Policy Act of 1978 (NGPA). In this order on rehearing, the Commission hereby amends § 275.204(f) to expand the notice requirements for a filed protest to a Notice of Determination to require that such notice be served upon "any persons who submitted or who sought an opportunity to submit written comments" as well as upon participants in the proceeding before the jurisdictional agency, as originally required. Further, § 275.206 has been amended to require that the Commission's notice to a submitter of information under § 274.104(a)(4) that such information will be made public be sent by telegram.

EFFECTIVE DATE: August 13, 1979.

FOR FURTHER INFORMATION CONTACT: Mark Magnusson, Office of the General Counsel, 825 North Capitol Street, NE., Room 4016-I, Washington, D.C. 20426, (202) 357-8511.

Order on Rehearing of Order No. 34

Issued August 13, 1979.

On June 14, 1979, Order No. 34 was issued in Docket No. RM79-3 by the Federal Energy Regulatory Commission (Commission). Order No. 34 issued final regulations in Part 275 of the Commission's regulations. Part 275 deals with the Commission's review of jurisdictional agency determinations of the appropriate classification of natural gas wells under the Natural Gas Policy Act of 1978 (NGPA). One application for rehearing was filed, by the Indicated Producers, on July 13, 1979.

Indicated Producers also filed, on February 28, 1979, an application for rehearing of the entire interim regulations. In that first application for rehearing, Indicated Producers alleged ten separate errors in the part 275 regulations. In its second application for rehearing, two more errors were alleged, and the previously alleged errors were incorporated by reference.

I. The February 28, 1979 Application for Rehearing

Almost all of the issues raised in Indicated Producers' first application for rehearing were addressed either in the preamble to the interim rules or the preamble to Order No. 34. However, certain other issues were not addressed; the Commission does so in this order on rehearing.

First, Indicated Producers claims that § 275.202(b) is unlawful. That section of the regulations authorizes the Commission to issue an "incomplete notice" if the jurisdictional agency's notice is inadequate. The Commission recognizes that the limited statutory grounds for reversal or remand [1] do not include those listed in § 275.202(b)(1).[2]

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[1] *See* Section 503(b) (1) and (2) of the NGPA.

[2] § 275.202(b)(1) allows an Incomplete Notice to be sent if "all the material information required in § 274.104(a) (4) and (5)" is not included in the Notice of Determination.

However, the issuance of an incomplete notice does not have the same effect as a reversal or remand. A reversal would terminate a producer's right to continue making interim collections. A remand would have the same effect after six months. See § 273.203(b)(2). An incomplete notice simply gives a jurisdictional agency a chance to correct certain deficiencies, and thus the statutory standards for reversal or remand do not apply. If the omission is not corrected, remand or reversal on the statutory grounds would be appropriate.

Further, the Commission is statutorily authorized, under section 503(a)(2) of the NGPA, to require, by rule, the information which must be submitted in the notice of determination. The incomplete notice is simply an extension of that authority, to enable the Commission to expeditiously exercise its review function.

Second, Indicated Producers claim that § 275.202(f), which involves the procedures following the issuance of a preliminary finding, does not allow interested parties to be formally apprised of the views of Staff or to respond to those views. Such is not the case. The Commission specifically expresses its views in the Notice of Preliminary Finding, and interested parties are allowed to respond in the informal conference provided for in § 275.202(d). Thus the rule will not be changed.

Indicated Producers did make one suggestion in its first application for rehearing that should be adopted. Section 275.204(f) requires a person who files a protest to a Notice of Determination to file that protest with all participants at the jurisdictional agency proceeding. However, Indicated Producer points out that § 274.104(a)(1) requires the Notice of Determination to include the names of all participants "as well as any persons who submitted or who sought an opportunity to submit written comments." The Commission agrees with Indicated Producers that all persons listed pursuant to § 275.104(a)(1) should be notified by the protestor of the protest. Therefore, § 275.204(f) has been amended accordingly.

II. The July 13, 1979 Application for Rehearing

As stated previously, Indicated Producers raised two additional issues in its second application for rehearing. The first involves § 275.205(d), which allows the Commission to include a refund obligation in a final order which reopens a final determination.[3] The Indicated Producers assert that "the producer/applicant may be ordered to refund monies some or all of which are later determined by subsequent well determination to have been lawfully collected." The Commission disagrees with this statement, because if a final determination is subsequently reopened by final Commission order, any rate collected pursuant to the reopened determination which is in excess of the otherwise applicable rate was not lawfully collected. Absent a valid final determination, the rate for the gas is controlled by either section 104, 105, 106 or 109 of the NGPA. See § 273.302(g)(2). The effect of a reopening is to negate the determination *ab initio*. Thus, a Commission ordered refund may be appropriate upon the reopening of a final determination.

Indicated Producers also object to the change made in Order No. 34 involving the notice provisions of § 275.206(b). That section sets forth the procedure that will be followed by the Commission upon a request under the Freedom of Information Act (FOIA), 5 U.S.C. 552, for information submitted in a notice of determination. The last sentence of § 275.206(b) now provides that five days notice will be given to the party submitting the information. Prior to Order No. 34 the notice period was ten days. The time period was shortened because the FOIA requires that non-exempt requested information must be divulged within ten days of the request, unless a written extension is submitted to the party requesting the information on one of the grounds enumerated in 5 U.S.C. 552(a)(6)(B). Since providing ten days notice to the party submitting the information is not one of the enumerated grounds for extending the ten day period for divulging the information, the notice period will remain five days. However, the Commission agrees that § 275.206(b) should provide for notice by telegram, and the rule will have been amended accordingly.

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[3] The Commission may reopen a determination if the determination was based on material misstatement or omission. *See* Section 503(d) of the NGPA.

The Commission Orders

The Application of Indicated Producers for rehearing of Order No. 34 is granted in part and denied in part.

(Natural Gas Act, as amended, 15 U.S.C. § 717, Department of Energy Organization Act, 42 U.S.C. § 7171, Natural Gas Policy Act of 1978, 15 U.S.C. § 3301)

For the reasons set forth above, the regulations of the Commission are amended as set forth below, effective for protests and FOIA requests filed thirty days after the issuance of this order.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,134]

45 F. R. 17959 (March 20, 1980)

18 CFR Part 292

[Docket No. RM79-54]

Small Power Production and Cogeneration Facilities—Qualifying Status

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts regulations that implement section 201 of the Public Utility Regulatory Policies Act of 1978. These rules set forth criteria and procedures by which small power producers and cogeneration facilities can obtain qualifying status to receive the rate benefits and exemptions set forth in the Commission's rules implementing section 210 of PURPA, which were issued on February 19, 1980 (45 FR 12214, February 25, 1980).

EFFECTIVE DATE: March 13, 1980.

FOR FURTHER INFORMATION CONTACT:

Ross Ain, Office of the General Counsel, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357-8446.

Bernard Chew, Office of Electric Power Regulation, 400 First Street, NE., Washington, D.C., (202) 376-9264.

James Liles, Office of Regulatory Analysis, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357-8158.

Adam Wenner, Office of the General Counsel, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357-9338.

SUPPLEMENTARY INFORMATION:

March 13, 1980.

Section 201 of the Public Utility Regulatory Policies Act of 1978 (PURPA) mandates that the Federal Energy Regulatory Commission (Commission) prescribe rules under which small power production facilities and cogeneration facilities can obtain "qualifying" status, and thus become eligible for the rates and exemptions set forth in the Commission's rules implementing section 210 of PURPA.

Section 201 of PURPA[1] defines a "small power production facility" as a facility which:

> (1) Produces electric energy solely by the use, as a primary energy source, of biomass, waste, renewable resources, or any combination thereof; and
>
> (2) Has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), is not greater than 80 megawatts.

A cogeneration facility is defined as a facility which produces electric energy and steam or forms of useful energy

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[1] Section 3(17)(A) of the Federal Power Act.

(such as heat) which are used for industrial, commercial, heating, or cooling purposes.[2]

Thus, cogeneration facilities simultaneously produce two forms of useful energy, namely electric power and heat. Cogeneration facilities can use significantly less fuel to produce electricity and steam (or other forms of energy) than would be needed to produce the two separately. By using fuels more efficiently, cogeneration facilities can make a significant contribution to the Nation's effort to conserve its energy resources.

Small power production facilities as defined in the Act use biomass, waste, or renewable resources, including wind, solar energy and water, to produce electric power. Reliance on these sources of energy can reduce the need to consume fossil fuels to generate electric power.

Prior to the enactment of PURPA, a cogenerator or small power producer seeking to establish interconnected operation with a utility faced three major obstacles. First, a utility was not generally willing to purchase the electric output or was not willing to pay an appropriate rate. Secondly, some utilities charged discriminatorily high rates for back-up service to cogenerators and small power producers. Thirdly, a cogenerator or small power producer which provided electricity to a utility's grid ran the risk of being considered an electric utility and thus being subjected to extensive State and Federal regulation.

Sections 201 and 210 of PURPA are designed to remove these obstacles. Each electric utility is required under section 210 to offer to purchase available electric energy from cogeneration and small power production facilities which obtain qualifying status under section 201 of PURPA, and to provide back-up power and other services to such facilities on a non-discriminatory basis. For such purchases, electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, which are in the public interest, and which do not discriminate against cogenerators and small power producers. Section 210(e) of PURPA provides that the Commission can exempt qualifying facilities from State regulation regarding utility rates and financial organization, from Federal regulation under the Federal Power Act (other than licensing under Part I), and from the Public Utility Holding Company Act. Finally, under section 206(c)(3) of the Natural Gas Policy Act of 1978 (NGPA), the Commission may exempt qualifying cogeneration facilities from the incremental pricing program under Title II of the NGPA.

In this rulemaking, the Commission sets forth requirements for qualifying cogeneration and small power production facilities and procedures by which such facilities may obtain qualification. Rules implementing section 210 of PURPA have been prescribed in Docket No. RM79-55.[3]

Any qualifying facility is eligible for the exemptions set forth in Subpart F of this part of the Commission's regulations immediately upon issuance of these rules. With regard to the rate benefits for qualifying facilities found in Subpart C of this part, however, the statute provides that the State regulatory authorities and nonregulated electric utilities will have up to one year to implement the Commission's rules. Therefore, the latest date by which qualifying facilities will be eligible to receive these PURPA-derived rate benefits is February 19, 1981.

I. Procedural History

On June 27, 1979, the Commission issued proposed rules in this docket [4] to determine which cogeneration and small power production facilities may become "qualifying" cogeneration or small power production facilities under section 201 of PURPA.

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[2] Section 3(18)(A) of the Federal Power Act.

[3] 18 C.F.R. Part 292, Subparts A, C, D and F; 45 FR 12214 (Feb. 25, 1980).

[4] 44 FR 38872 (July 3, 1979).

Public hearings on RM79-54 were held in San Francisco on July 23, 1979, Chicago on July 27, 1979, and Washington, D.C. on July 30, 1979. Written comments were also received.

On October 18, 1979, the Commission issued a Notice of Proposed Rulemaking Under Section 210 of PURPA in Docket No. RM79-55.[5] On October 19, 1979, the Commission made available its preliminary Environmental Assessment (EA) of the proposed rules in Docket Nos. RM79-54 and RM79-55.

In a Request for Further Comments,[6] the Commission requested further public comment on both proposed rules, and on the findings set forth in the preliminary EA. In order to obtain the data, views, and arguments of interested persons, the Commission Staff held public hearings in Seattle on November 19, 1979, in New York City on November 28, 1979, in Denver on November 30, 1979, and in Washington, D.C. on December 4 and 5, 1979. The Commission also received written comment. All of the comments were considered in the formulation of this final rule.

II. Summary

These rules set forth criteria and procedures by which cogeneration and small power production facilities can obtain qualifying status to receive the rate benefits and exemptions set forth in the Commission's rules implementing section 210 of PURPA.

The rules in this docket permit qualification without a need for specific Commission action. They also make available an optional procedure under which, should it prove desirable, a facility can gain certification as a "qualifying facility." For qualifying small power production facilities, the efficiency standards contained in the proposed rule have been eliminated, and the permitted level of oil, natural gas and coal use for startup, testing, flame stabilization, and operation during outages of the primary energy supply system has been increased and the form of that requirement has been simplified. For qualifying cogeneration facilities, efficiency standards still must be met by certain new facilities using oil or gas. In addition, certain operating standards have been adopted for purposes of assuring that a qualifying cogenerator is a *bona fide* cogenerator.

III. Section-by-Section Analysis

§ *292.201 Scope*

Section 292.201 describes the scope of Subpart B of the Commission's rules. Subpart B provides the criteria for and manner of qualification of small power production and cogeneration facilities.

§ *292.202 Definitions*

This section contains definitions applicable to this subpart of the Commission's rules.

Paragraph (a) defines "biomass" as any organic material not derived from fossil fuels. The proposed rule defined "biomass" as plant materials which are obtained from cultivation, or harvested from naturally occurring vegetation without significant depletion of the resource. Commenters recommended that the Commission expand the definition to include any organic material not derived from fossil fuels. The commenters stated that most studies dealing with energy recovery from organic material other than fossil fuels have included municipal (and most industrial) solid waste within the more general category of biomass.

The Commission agrees with the commenters who urged the Commission to expand the scope of this definition. The Commission observes that applying a narrow definition of biomass might hinder development of small power production facilities between 30 megawatts and 80 megawatts in capacity. Use of a definition of biomass which includes by-products of the manufacturing, harvesting, and growing of agricultural products, including wood, will enable a greater number of small power producers between 30 and 80 megawatts to take advantage of the exemption from State law and regulation regarding rates and financial organization of electric utilities and from the Public Utility Holding Company Act, as provided in subpart F of this part of the Commission's rules.

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[5] 44 FR 61190 (Oct. 24, 1979).

[6] 44 FR 61977 (Oct. 29, 1979).

One commenter questioned whether the Commission meant to include peat within the definition of biomass. The Commission wishes to clarify this point by stating that peat is included in the definition of biomass for purposes of this subpart.

Paragraph (b) defines "waste" as any by-product materials other than biomass. In most instances, waste is a by-product of fossil fuels. Examples of waste include petroleum coke, refinery gas, and plastics.

Paragraph (c) defines "cogeneration facility" as equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes, through the sequential use of energy.

Several commenters requested clarification of the applicability of the Commission's rules to cogeneration in the residential sector. The issue arises because of the absence of any explicit mention of residential energy use in the statutory language. The Commission's definition of cogeneration facility tracks the statutory language in that residential use is not specifically identified.

The Commission intends that residential sector cogeneration be included. The Commission believes that the phrase "heating, or cooling purposes" applies to any industrial, commercial, or residential heating or cooling purpose. The Commission has not found anything in the legislative history of PURPA which suggests that the terms "industrial" and "commercial" were intended to modify "heating, or cooling". Separate mention of "residential" use is unnecessary because heating and cooling adequately encompass the residential use of thermal energy. In the industrial sector, thermal energy in the form of process steam is used as an input to many industrial processes. The separate identification of industrial and heating uses is necessary since not all industrial uses of thermal energy are for heating or cooling purposes. In addition, in many instances, commercial heating purposes include heating of residential apartment buildings, so that the exclusion of residential heating and cooling from this program would be difficult to accomplish even if such purpose were within the realm of statutory construction.

Sequential Use

Several commenters recommended that the Commission define cogeneration as the "combined" or "joint" production of heat and power. However, the terms "combined" or "joint" production of heat and power do not fully describe the cogeneration process. The final rules contain an explicit requirement for the sequential use of energy in cogeneration facilities. This means that rejected heat from a power production or heating process is used in another power production or heating process. It is precisely this "cascading" use of energy in sequential processes that gives rise to the energy conserving characteristic of cogeneration.

By adding the phrase "through the sequential use of energy" to the definition of cogeneration facility, the Commission makes explicit what was intended in the proposed rule. The discussions in the proposed rule relating to topping and bottoming-cycle cogeneration and the efficiency standards were expressed in the context of sequential use. Many commenters apparently recognized this fact and, in their discussions of alternative efficiency standards, compared hypothetical cogeneration systems to reference cases of noncogeneration, separate production of heat and power. Additionally the explanation of supplementary firing in the proposed rules implied that energy inputs other than supplementary firing would have to flow through both a thermal and a power production process. The explicit mention of sequential use is therefore not a new requirement; it is a clarification of intent.

Several comments filed in this rulemaking in response to the Commission's November 9, 1979 Interim Rule [7] raised questions about how the sequential use concept would apply in certain situations. One commenter noted that many industries commonly route steam directly from their boilers to processes without expansion in a turbine. This practice is simply the raising of process steam; it is not cogeneration. The fact that some other steam from the same boiler is routed to cogeneration equipment does not mean that all steam from the boiler is used for cogeneration. The coincident raising of process steam relates to the cogeneration rules in two ways. First, any energy expended in raising such steam should not be entered into any efficiency calculations. Secondly, natural gas used for raising process steam is not rendered exempt from incremental pricing solely because the boiler may also supply steam for cogeneration.

A commenter also questioned the applicability of the sequential use test to a combustion turbine coupled with a waste heat recovery boiler. The commenter noted that the boiler could not capture all of the heat in the turbine exhaust and thus not all of the turbine's power could be said to be sequential. The Commission does not adopt this interpretation. The high efficiency of combustion turbine/waste heat recovery boilers derives from the fact that a substantial quantity of waste heat is recovered. The Commission does not require that all heat be recovered. Strictly speaking, some of the available thermal energy in a steam turbine cogeneration system is lost (due to pressure drop in piping along with convective and radiative heat losses) before the steam is delivered to a useful process. As long as any applicable efficiency and operating standards are met, the Commission is not concerned with energy losses within the system.

A final issue concerning the definition of a cogeneration facility involves combined-cycle electric generation plants. Such plants burn gaseous or liquid fuels in a combustion turbine and use the turbine exhaust to raise steam. The steam is directed through a fully condensing steam turbine. Only electricity is produced, albeit through the sequential use of energy. The Commission is of the opinion that combined-cycle electric generation plants are not cogeneration facilities, since only one form of energy is produced.

In paragraph (d), the Commission has added the definition of "topping-cycle cogeneration facility" which is a cogeneration facility in which the energy input to the facility is first used to produce power, and the reject heat from power production is then used to provide useful heat.

Paragraph (e) has been added to define a "bottoming-cycle cogeneration facility" as a cogeneration facility in which the energy input to the system is first applied to a useful heating process, and the residual heat emerging from the process is then used for power production.

The Commission has added paragraph (f), which defines "supplementary firing" as an energy input to the cogeneration facility used only in the thermal process of a topping-cycle cogeneration facility, or only in the electric generating process of a bottoming-cycle cogeneration facility.

The distinguishing characteristic of supplementary firing as defined here is that none of the energy is used sequentially. In topping cycles, supplementary firing is commonly practiced by introducing natural gas or oil into the hot exhaust of a combustion turbine. The turbine exhaust will typically have sufficient oxygen to support combustion of the added fuel.

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[7] Interim Rule for Qualification of Gas-fired Cogeneration Facilities for Purposes of the Incremental Pricing Program, 44 FR 65744 (Nov. 15, 1979).

The resulting heat can either be used directly in a high-temperature direct heat application or used to raise process steam. Supplementary firing is also possible in steam turbine cogeneration facilities, through reheat of steam which exists from a turbine. In all cases, the added energy is not used to produce power as well as useful thermal energy.

In a bottoming-cycle cogeneration facility, supplementary firing can be used to increase the output of the power production equipment by firing additional fuel in the thermal process exhaust. Again, the added energy is not used sequentially for both power production and a thermal process.

Commission recognizes that there will be questions as to the application of the standards of this subpart to complex facilities which may contain combinations of topping and bottoming-cycle cogeneration equipment. The optional procedure for qualification under § 292.207 is available specifically to help any cogenerator who wishes clarification as to whether his facility would qualify.

Paragraph (g) adds the definition of "useful power output" of a cogeneration facility as the electrical or mechanical energy made available for use, exclusive of any such energy used in the power production process. Although electric power output is required of a qualifying facility, any additional mechanical power may be taken into account in determining "useful power output".

Paragraph (h) has been added to define "useful thermal energy output" of a topping-cycle cogeneration facility as the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application.

The proposed rules contained a definition of the "useful energy output of a thermal process." The term was intended to reflect the heat actually used in a thermal process rather than heat made available for use. The proposed term found application in proposed efficiency standards for both topping and bottoming cycles. Only a few commenters mentioned the proposed term, but they did raise serious questions about the feasibility (and desirability) of performing the necessary calculations. It was argued that computation of the "useful energy output of a thermal process" in accordance with the proposed definition would be difficult and would yield unintended results—particularly in the case of bottoming cycles.

The Commission notes that in its final rules the efficiency of bottoming-cycle facilities is evaluated only with respect to supplementary firing. No evaluation of efficiency is now required for the thermal process of a bottoming cycle.

For new topping-cycle facilities burning natural gas or oil, however, the degree to which heat is recovered and put to use remains a concern. The final rules contain a definition of "useful thermal energy output" which eliminates the problems of the proposed terminology. Under the new definition, in the case of industrial or commercial process use of thermal energy, the thermal energy made available for use in the process may be considered useful thermal energy output of a cogeneration facility. Thus an industrial process which uses steam or heat need not be analyzed for the purpose of determining what fraction of the energy delivered to the process is actually put to use.

In the case of space heating and cooling, water heating, and related heating and cooling applications, a cogeneration facility's useful thermal energy output is the energy actually used in the application. For example, a cogeneration facility may consist of a combustion turbine with exhaust heat recovery used for space heating. In this example, the useful thermal energy output would be the heat recovered from the exhaust and actually used for space heating, not all of the heat available in the exhaust.

Paragraph (i) defines "total energy output" of a topping-cycle cogeneration facility as the sum of the useful power output and useful thermal energy output.

Paragraph (j) defines the term "total energy input" as the total energy of all forms supplied from external sources,

best copy available

other than supplementary firing, to the facility.

The total energy input to a cogeneration facility includes all fuels and renewable resources used in the facility. Energy taken from one part of the facility and used in another part of the cogeneration process does not meet the test of being supplied from an external source. For example, boiler feedwater pumping, heating, and deaerating are energy uses internal to the cogeneration facility and are not to be considered as either energy inputs or energy outputs.

The Commission has added the definition of natural gas in paragraph (k) as it is defined in the Natural Gas Act, which is natural gas unmixed, or any mixture of natural gas and artificial gas. This is intended to cover natural gas supplied by any natural gas company as defined in the Natural Gas Act or any distribution company selling natural gas. As a result, the efficiency standards under § 292.205 only apply with respect to the natural gas so defined and do not apply with regard to any synthetic gas which is unmixed in the pipeline, or mixed by the end-user, such as coke oven gas, blast furnace gas, or gas derived from coal or shale oil.

The definition of "oil" has been added in paragraph (l) to mean crude oil, residual fuel oil, natural gas liquids, or any refined petroleum products. This definition does not include refinery-off gas, petroleum coke, or other waste products of the refinery process.

Finally, the Commission has provided in paragraph (m) that, for purposes of this subpart, in the case of energy in the form of natural gas or oil, energy input is to be measured by the lower heating value of such fuel.

In the proposed rules, energy inputs in the form of fossil fuels were to be evaluated in terms of the lower heating value of such fuels. A few commenters took issue with the use of lower heating values and recommended that higher heating values be specified in the final rule.

Lower heating values were specified in the proposed rules in recognition of the fact that practical cogeneration systems cannot recover and use the latent heat of water vapor formed in the combustion of hydrocarbon fuels. By specifying that energy input to a facility excludes energy that could not be recovered, the Commission hoped that the proposed energy efficiency standards would be easier to understand and apply. The Commission also wished to a apply a standard that would be more uniform in the treatment of natural gas and oil. Owing to the difference in chemical composition, more latent, unrecoverable heat is lost in the combustion of gas as compared to oil. The Commission did not wish indirectly to make qualification more difficult for natural gas-fired cogeneration facilities by requiring a higher level of sensible heat recovery.

The commenters opposing the use of lower heating values generally argued that customary practice is to use higher heating values. The Commission does not find this argument compelling. Both heating values of fuels can easily be found in handbooks. Moreover, if a cogenerator wishes to use the higher heating value of fossil fuel inputs for computing efficiency, the Commission has no objection. Any facility qualifying with efficiency so computed would certainly qualify under the more lenient rules set forth. As a result, the Commission does not believe it appropriate to change this aspect of the proposed rule in this final rule.

§ 292.203 General requirements for qualification.

The proposed rule provided that any person seeking qualifying status for a facility had to initiate discussions with the utility with which it wishes to interconnect and file an application with this Commission. The proposed rule set forth the contents of an application for certification which included technical information describing the facility, a summary of discussions required to be held between the applicant and the affected electric utility, and a description of the equity ownership of the facility. In addition, a small power producer was required to provide information about its primary energy source and its location. A cogenerator was required to submit information describing the energy input and output of the facility in both the heat engines and thermal processes.

The majority of comments favored eliminating the filing requirement either for all qualifying facilities or for specific classes of qualifying facilities. Several commenters suggested that the complexity, delays, and uncertainties created by a case-by-case qualification procedure would act as signficant economic disincentive to owners of smaller facilities. Other commenters recommended exempting smaller facilities, such as facilities with an aggregate electrical capacity of up to 250 or 500 kW, from formal filing requirements. A utility [8] stated that the application procedure does not serve any party or the public's interest. This commenter preferred to see regulations on an "exception" basis where the utility, State regulatory authority or other interested party could object to the granting of qualifying status.

The Commission finds substantial merit in these comments. The Commission believes the initiation of purchase and sale arrangements, pursuant to Subpart C of this part of the Commission's rules, will necessitate the flow of information between potential qualifying facilities and affected electric utilities. The Commission therefore notes that the requirements contained in the proposed rule both for discussions between a potential qualifying facility and the utility with which it wishes to interconnect and for the filing of substantial information with this Commission are not necessary.

For example, one commenter [9] suggested modifying the pre-application negotiation requirements to require that an applicant initiate discussions with the utility prior to filing if the cogenerator or small power producer is intending to negotiate an individual contract. However, if the applicant merely wants to establish his eligibility for an already-published rate schedule for qualifying facilities, this commenter claims that there would be nothing to negotiate, and thus no reason to require that discussions be held. It was asserted that notification to the utility at the time of application would suffice in such cases. The Commission believes that this is what would and should happen without any requirement from the Commission. In addition, the Commission believes that, as a practical matter, an electric utility, which is notified by a qualifying facility that it wishes to interconnect with the utility in order that the utility may purchase the power produced by the facility, will need to know the nature of the qualifying facility's expected purchases and sales so as to be able to arrange safe and reliable interconnected operation at appropriate rates.

As a result, the requirement for case-by-case qualification has been eliminated. Section 292.207(a) of this rule provides that any small power production or cogeneration facility which meets the requirements for qualification set forth in that section is a qualifying facility.

However, the Commission has provided an optional procedure in § 292.207(b) of this rule whereby an application for Commission certification of qualifying status may be filed at the discretion of the owner or operator of the facility.

There was some confusion in the comments as to who actually qualifies under this program. The facility qualifies and that entitles the owners and operators of the facility to receive the benefits of qualification under this part. The benefits of qualification under this part, however, are only with respect to the qualifying facility. For example, the owner or operator of a qualifying cogeneration facility is entitled to require the utility to sell power to his qualifying facility in compliance with the terms of § 292.305 as implemented by the State regulatory authority. The owner or operator has no entitlement to require such rate treatment for the utility's sales to other facilities he may own or operate which are not qualifying facilities. Similarly, his sales to the utility will be exempt under Subpart F of this part from certain Federal and State regulation only to the extent the sales are from a qualifying facility.

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[8] Pacific Gas and Electric Company.

[9] U.S. Department of Energy.

§ *292.203(a) Small power production facilities.*

Section 292.203(a) provides that a small power production facility is a qualifying facility if it meets three criteria.

The first requirement is that the power production capacity of the facility, together with the capacity of any other facilities that use the same energy resource and are owned by the same person and are located at the same site, may not exceed 80 megawatts. The method by which the capacity is determined is described in this preamble under § 292.204.

The second requirement is that the primary energy source of the facility must be biomass, waste, renewable resources, or any combination thereof. This means that more than 50 percent of the total energy input must be in these categories. In addition, the aggregate use of oil, natural gas, and coal by the facility may not exceed 25 percent of its total energy input during any calendar year. These fuel use criteria are discussed further in § 292.204(b).

Thirdly, a small power production facility will not be eligible for qualifying status if more than 50 percent of the equity interest in the facility is held by an electric utility or public utility holding company or any person owned by either. Section 292.206 describes this ownership test in greater detail.

One commenter raised the question as to whether a facility is included within the definition of a small power production facility in the statute, and hence the Commission's regulations, if the facility is only part of the process of producing electric energy; namely, raising steam. This commenter produces steam using municipal solid waste, which steam is then sold through an adjoining wall to an electric utility to run through a turbine and produce electricity. In a sense, this facility indirectly produces electric energy. It is unclear to the Commission how this steam-raising facility would benefit from the regulations under section 210. It is not selling electric energy to the utility; it may be buying some electric energy from the utility; and it seems unlikely that it would be subject to electric utility regulation. Therefore, the Commission does not, at this time, see the need to allow qualification for these kinds of facilities, without judging as to whether the Commission could allow such qualification under the statute.

§ *292.203(b) Cogeneration facilities.*

Section 292.203(b) provides that, with the exception of new diesel cogeneration facilities, a cogeneration facility may be a qualifying facility if it satisfies two requirements. First, it must meet the same ownership test as that required for a small power production facility. Secondly, it must meet any operating and efficiency standards described in § 292.205(a) and (b).

In addition, cogeneration facilities which wish to qualify for the incremental pricing exemption permitted under Title II of the Natural Gas Policy Act of 1978 (NGPA) and Part 282 of the Commission's rules must meet the requirements stated in § 292.205(c).

Section 201 of PURPA provides that "a 'qualifying cogeneration facility' means a facility which—(i) the Commission determines, by rule, meets such requirements (including requirements respecting minimum size, fuel use, and fuel efficiency) as the Commission may, by rule, prescribe * * *". Several comments contended that the statutory language *requires* the Commission to establish standards relating to all of the mentioned criteria. The legislative history of this section indicates that the phrase "as the Commission may * * *" was added in conference; it did not appear in either the House or Senate bill.[10] The plain meaning of the provision, as adopted by the Conferees, is that a qualifying cogeneration facility must meet requirements that the Commission, in its discretion, establishes. These may, but need not, include requirements respecting minimum size, fuel use, and fuel efficiency.

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[10] See Comparative Print to H.R. 4018, Public Utility Regulatory Policies Act, 72, 95th Cong., 2d Sess. (1978).

The Commission received numerous comments from utilities recommending that oil- and natural gas-fired cogeneration facilities not be considered eligible for qualifying status. These commenters generally argued that encouragement of such facilities would be contrary to Congressional intent and national energy policy. Comments were also received expressing strong support for the policy presented in the proposed rule, which did not impose a restriction on oil and natural gas use.

The Commission believes the policy expressed in the proposed rules is consistent with Congressional intent and national energy policy. Had Congress not intended that the benefits of qualifying status be extended to oil- and natural gas-fired cogeneration facilities, the statute or Joint Explanatory Statement of the Committee on Conference (Conference Report) would have contained a restriction on fuel use similar to that which is provided for small power producers. The Congress knew that cogeneration facilities typically use natural gas and oil. In addition, the Natural Gas Policy Act of 1978 contains an express exemption from the incremental pricing program for natural gas used in qualifying cogeneration facilities, which further indicates Congressional recognition that cogeneration facilities use natural gas.

Thirdly, the Congress enacted the Powerplant and Industrial Fuel Use Act (PIFUA) at the same time as PURPA. PIFUA provides authority to the Secretary of Energy to restrict the use of oil and gas in cogeneration facilities. Therefore, the Commission does not believe it necessary or appropriate to require an additional layer of fuel use regulation on technologies which the Commission is charged with encouraging and for which another agency has authority to restrict fuel use.

The Commission also notes that the findings in section 2 of PURPA specifically require "a program providing for * * * increased efficiency in the use of facilities and resources * * *". To the extent that oil- and natural gas-fired cogeneration facilities provide for more efficient use of these resources, the Commission believes that the benefits of qualifying status should be extended to them.

Some of the comments stated that permitting qualifying cogeneration facilities to use oil, especially in diesel engines, will use up available air quality increments, thereby preventing the conversion of large utility oil-fired boilers to coal. As noted above, the Commission believes it is not proper to address this fuel use issue within the context of this program. However, the Commission has not made a final determination regarding the environmental effects of new diesel cogeneration facilities, and is therefore including in these regulations an interim exclusion from qualification of this technology until work on an environmental impact statement has been completed.

§ *292.203(c) Interim exclusion.*

Section 292.203(c) provides that, pending further Commission action, any cogeneration facility which is a new diesel cogeneration facility may not be a qualifying facility. A new diesel cogeneration facility is described as a cogeneration facility which derives its useful power output from a diesel engine, the installation of which began on or after March 13, 1980.

Through the issuance of these rules and the rules implementing section 210 of PURPA, the Commission intends to carry out the legislative mandate to provide encouragement to the energy technologies included within the program. The Commission is required under the National Environmental Policy Act of 1969 (NEPA) to take the environmental effects of this encouragement into account. The

Commission has circulated and received public comment on a preliminary Environmental Assessment (EA) of these rules which was issued on October 19, 1979.

(See Appendix I)

Environmental Findings

The identification of the environmental effects associated with a "major Federal action"[11] is not ordinarily a difficult task. These effects typically are those associated with the construction and operation of a particular project in which the Federal government is playing a major role, such as by funding or licensing. In contrast, these rules and the rules implementing section 210 of PURPA do not authorize or fund any particular projects; moreover, they do not authorize or forbid the use of certain fuels. Instead, they provide certain economic incentives to, and remove other disincentives (*i.e.*, assurance of a market for electrical production and exemption from utility regulation) from certain classes of technologies. It is important to note that, even without these rules, these technologies have been, and would continue to be, utilized. The environmental effects associated with this "base-case" level of development cannot be ascribed to these rules. Instead, the proper way to isolate and identify the effects of these rules is to predict the "base-case" (no PURPA) level of development, and determine the environmental effects of that level of development, and compare it to the effects of the projected development with these rules in place. Under this approach, any changes from the base-case review are properly classified as effects of these rules.

The first step used in determining the environmental effects of these rules was to compare, by region, representative electric utility rates with the cost of generating electricity by use of a qualifying facility. This comparison established which technologies would be economically viable. Next, the costs of generating electricity by the facility were compared to an estimate of utilities' avoided costs on a regional basis. If, by receiving the avoided cost for its output, a facility would operate economically, it was considered to have been "PURPA-induced." Avoided cost is the maximum price inducement under this program.

For technologies which would, as a result of PURPA, be economic, regional levels of market penetration were established on the basis of site availability and manufacturing capability. Finally, the environmental effects associated with the predicted level of development were calculated.

The Environmental Assessment accompanying this order describes the environmental effects associated with all of the types of technologies encompassed in section 201 of PURPA. The quantitative effects associated with the predicted market penetration of each technology were then estimated.

The Environmental Assessment includes an extensive market-penetration analysis of each technology eligible for qualification under the Commission's proposed rules and of the aggregate of all of these technologies. Since the proposed rules took the broadest view of which technologies would be eligible for qualification, the analysis covers all technologies, which, under the statute, may be eligible for qualification. On the basis of this analysis, the Commission has estimated the amount of capacity expected to be induced on a regional and national basis through January 1, 1995, assuming the broadest implementation of this program.

This analysis shows that this program may result in the construction of 12,000 MW of new capacity by qualifying facilities by 1995, and the reduction in utility construction of 10,000 MW of new capacity. It also indicates a possible fuel savings in 1995 of 40,000 bbl/day of oil, 40,000 bbl/day equivalent of natural gas, and 120,000 bbl/day equivalent of coal as the use of renewable resources increases, and more efficient use is made of both renewable and nonrenewable resources.

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[11] Section 102(2)(c) of the National Environmental Policy Act of 1969, Pub. L. 91-190.

The Environmental Assessment finds that there will be both adverse and beneficial environmental effects associated with this program. Some of the technologies produce certain air emissions, water effluents, and other environmental effects. However, material and thermal by-products of industrial, commercial, agricultural and other activities that would otherwise contribute to environmental degradation will be consumed or otherwise utilized in the production of useful energy under this program.

In addition, the Environmental Assessment indicates that utilities will be able to defer or cancel construction of certain facilities, originally scheduled for construction between 1980–1995. These deferrals or cancellations are expected to include some eleven 500 MW coal-fired steam plants, one 1,000 MW nuclear plant, a number of 75 MW gas turbines, and certain large scale hydropower and combined cycle installations. The environmental impacts associated with the construction and operation of these facilities would be avoided.

Finally, the market-penetration analysis in the Environmental Assessment indicates that the incentives provided by this program will not significantly affect the development of some technologies while they will significantly encourage others. For example, it appears that this program will significantly encourage small hydroelectric power development. Water power project impacts are usually site-specific and localized, with no cumulative impact on a national basis, and few impacts of regional significance. The Commission notes that hydroelectric projects in almost all cases must be licensed by the Commission. License applications are evaluated on a case-by-case basis to determine the significance of the environmental impacts and the need for a site-specific EIS. In addition, impacts of individual projects on a waterway may be cumulative, and the Commission reviews each project in relation to others on the waterway under the "comprehensive development" standard of section 10(a) of the Federal Power Act. Therefore, even though only the general nature of the kinds of environmental effects can be evaluated in this programmatic environmental assessment of national scope, requirements of the National Environmental Policy Act of 1969 (NEPA) will be met as each application is filed.

For certain other technologies, the level of environmental effects associated with the PURPA-induced market penetration of these technologies will not approach a significant level in the near term.[12] The Commission will monitor the PURPA-induced market penetration of these technologies carefully.

In the public comments, evidence was presented indicating that the environmental consequences of qualifying new diesel cogeneration may be significant in the near term, in certain geographic areas, even with a moderate level of market penetration. Therefore, the Commission believes that it is appropriate to delay action on qualification of new diesel cogeneration until completion of an EIS. The Commission will circulate a draft EIS within the next month and conclude its analysis within 90 days of circulation.

The Commission acknowledges the difficulties in identifying the levels of the environmental effects associated with the programmatic encouragement and deregulation of various types of technologies as are present under this program. There are, of course, a great number of uncertainties in any such analysis. However, the Commission is required under NEPA to assess these effects to the fullest extent possible.

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[12] See Figures 3 through 7 in the Environmental Assessment.

On the basis of its environmental review, the Commission has made the following findings in its Environmental Assessment:

—The program, taken as a whole, will not have a significant impact on the quality of the human environment within the meaning of section 102 of NEPA. The Commission also has noted certain beneficial environmental impacts that may result from this program.

—Where the expected market penetration of technologies which could qualify under this program is not expected to cause any significant environmental effects in the near term, the Commission will allow qualification of these technologies without delay.

—Where a technology is expected to cause significant environmental effects in the near term, an EIS covering the technology will be prepared and considered before the Commission acts on qualification.

—The Commission is establishing a monitoring program to alert the Commission to the likelihood or extent of market penetration by technologies which qualify under this program. This is designed to produce information that may be relevant to taking appropriate environmental protection action in the future before the program reaches a stage of investment or commitment to implementation likely to determine subsequent development or restrict later alternatives.

§ 292.204(a) Criteria for qualifying small power production facilities.

Section 292.204 sets forth qualification requirements for small power production facilities. Paragraph (a) implements the statutory requirement that the power production capacity of a small power production facility not exceed 80 megawatts at any site. In order to implement this limitation, the proposed rules provided that the capacity of all facilities which use the same energy resource, are owned by the same person, and are located within one mile of each other be added together. Commenters recommended eliminating the site criterion because the important criterion is not siting but that facilities use alternate energy resources. The Commission recognizes the difficulty in prescribing site criteria for purposes of calculation of the size of the facility. However, the Commission is obligated under the statute to limit qualifying status for small power production facilities to those facilities which have "a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), is not greater than 80 megawatts." [13]

In subparagraph (2)(i), the Commission defines "facilities located at the same site" as facilities located within one mile of the facility for which qualification is sought. Hydroelectric facilities (within this distance) are considered to be located at the same site only if the facilities use water from the same impoundment for power generation. The Commission views this additional provision for hydroelectric facilities as necessary because use of the one-mile rule alone might discourage the development of facilities on separate waterways which are within one mile of each other or of closely-spaced impoundments on an individual stream.

The Commission also notes that in some instances hydropower resources may be developed without an impoundment. In this case, the one-mile rule would be the only factor in determining the size of a facility.

In response to comments, the Commission has added subparagraph (2)(ii) which requires, for purposes of determining the distance between facilities, that any measurement shall be made from the electrical generating equipment of a facility. The comments noted that some facilities may include equipment for gathering energy to be used in the facility which may extend up to a number of miles from the generating facility. The Commission believes that the one-mile limit should be measured from the generating facilities.

The proposed rule enabled an applicant to rebut the presumption that facilities located within one mile of the facility for which qualification is sought, using the same energy resource and owned by the same person, should be considered to be located at the same site. The Commission believes that the requirement to rebut the presumption was burdensome and confusing. Therefore, the final rule has been revised to enable a small power producer or cogenerator to apply to the Commission for a waiver for good cause.

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[13] Section 3(17)(A)(i) of the Federal Power Act.

The proposed rule also contained a minimum size limit of 10 kW for qualification of small power production facilities. This proposal was based on the Commission's view that facilities smaller than 10 kW were unlikely to be economically viable, and that the administrative burden of arranging interconnected operation with them would be greater than the benefits they would provide to the system at this time. This proposal attracted considerable comment, both at the public hearings and in written recommendations. The majority of the comments objected to the minimum size provision and indicated that a number of facilities smaller than 10 kW are being built and that some units are presently commercially available. Commenters also stated that these facilities can be equipped with electrical protection equipment which permits safe interconnected operation.

Several utilities, on the other hand, suggested raising the minimum size limit, arguing that small facilities are not cost-effective. The Commission notes that the rules implementing section 210 of PURPA (Subpart C of this part) require that standard rates be provided for facilities up to 100 kW. Those rules together with the self-qualification provisions of these rules greatly ease the administrative burdens on all parties. The Commission also notes that the rules implementing section 210 of PURPA require that a qualifying facility is obligated to pay any interconnection costs assessed against it by the State regulatory authority or nonregulated electric utility. Since under these rules the utility is not obligated to incur any additional costs by reason of interconnected operation with these facilities, the minimum size limitation has been eliminated to allow individual decisions to govern whether or not to install these very small facilities.

§ *292.204(b) Fuel Use.*

Paragraph (b) sets forth fuel use requirements for qualifying small power production facilities. In the proposed rule, the term "primary energy source" was not defined. Several commenters noted this fact and asked that the final rules specify a definition for the term. Subparagraph (1) provides that the primary energy source of the facility must be biomass, waste, renewable resources, or any combination thereof, and more than 50 percent of the total energy input must be from these sources. The Commission notes that this requirement is not intended to force small power producers to continually monitor the energy input, but rather that reasonable estimates based on sampling methods are sufficient.

Qualifying small power production facilities using biomass as a primary energy source are treated differently than are facilities using other resources for purposes of exemption from the Public Utility Holding Company Act and certain State law and regulation under section 210(e) of PURPA and under § 292.602 of the Commission's regulations. A further concern in determining a facility's primary energy source is the treatment of mixtures of biomass and waste or renewable resources. Therefore, in subparagraph (1), the Commission specifies that any primary energy source which, on the basis of its energy content, is more than 50 percent biomass shall be considered biomass. In other words, a qualifying facility may be considered biomass-fired if, on an estimated annual basis, at least half the energy input, exclusive of fossil fuel use, is biomass.

The Commission expects that this rule will extend the benefits of the biomass exemption provisions to a broad range of facilities. For example, evidence presented in this rulemaking indicated that much more than half of the energy content in municipal solid waste is due to "organic material not derived from fossil fuels," or "biomass" under the Commission's definitions. Thus, a small power production facility fired with municipal solid waste may be considered a biomass facility. The same treatment applies to facilities fired with forest-industry residues, sewage sludge, or peat.

Another aspect of what constitutes "primary energy source" is a specification of what fuels may be used in addition to the primary energy source for purposes of ignition, startup, testing, flame stabilization and control, and during equipment outages and emergencies.

Section 3(17)(B) of the Federal Power Act, as amended by section 201 of PURPA, provides that:

> " 'Primary energy source' means the fuel or fuels used for the generation of electric energy except that such term does not include, as determined under rules prescribed by the Commission, in consultation with the Secretary of Energy—
>
> "(i) The minimum amounts of fuel required for ignition, startup, testing, flame stabilization, and control uses, and
>
> "(ii) The minimum amounts of fuel required to alleviate or prevent—
>
> "(I) Unanticipated equipment outages, and
>
> "(II) Emergencies, directly affecting the public health, safety, or welfare, which would result from electric power outages."

The proposed rule set forth limits for the allowable use of fossil fuels. Three separate standards were proposed: One for ignition, startup and testing; another for flame stabilization and control; and a third for fuel use during outages of the primary energy supply system. All of the proposed standards were set in terms of barrels of oil per year per megawatt of rated capacity.

The comments filed on this section generally favored less restrictive fossil fuel limitations. Several commenters noted that standards written in terms of barrels of oil were imprecise, since the energy content of a barrel of oil is not constant. Other commenters argued that separate standards for startup, flame stabilization and outages were unnecessarily burdensome. Commenters claimed that some small power production technologies would be severely constrained by one of the standards, while requiring little or no fossil fuel for other purposes. Additionally, to the extent oil and natural gas remain more expensive than other energy sources available to small power producers, there is an economic disincentive to use oil and natural gas. Thus it was argued that a single standard for allowable fossil fuel use would be more equitable and workable when dealing with a number of types of facilities. The Commission has decided to adopt this recommendation.

Many other commenters recommended that the Commission adopt alternative amounts of fossil fuel for use during outages and for other purposes. For the purpose of specifying the minimum amounts of fuel under clauses (i) and (ii) of section 3(17)(B) of the Federal Power Act, the Commission adopts in this rulemaking the standard, recommended by several commenters, that no more than 25 percent of the total energy input during any calendar year may consist of fossil fuels—namely oil, natural gas, and coal.

With this simple rule, a qualifying facility can use up to the allowed quantity of fossil fuel for purposes specified in the statute. No question remains concerning what sort of primary fuel system supply outages are within the scope of the rule. The standard does require that a small power producer be able to estimate the energy content of the primary energy source. The Commission recognizes that for some energy sources, municipal solid waste in particular, energy content is not constant. As has been stated earlier, the Commission believes that reasonable estimates will suffice for purposes of this rule. Finally, it should be noted that the fossil fuel limitation applies only to small power production facilities. Some commenters apparently regarded the limitations as equally applicable to cogeneration facilities. This is not the case.

Another issue raised by the proposed rule was the limitation of renewable resources to water used at existing dams. Commenters urged the Commission to expand the definition of renewable resources to include water used at new hydroelectric facilities. The

Commission has reviewed the Conference Report and has determined that the conferees did not intend to restrict the term renewable resources to water used only at existing dams. The Commission believes that such an interpretation conflicts with the conventional use of the term "renewable resources" as including all hydroelectric sources, not just those using existing dams. Therefore, the Commission intends that the term renewable resources applies to water used at existing and new hydroelectric facilities of less than 80 megawatts.

§ *292.205 Criteria for qualifying cogeneration facilities.*

§ *292.205(a)(1) Operating standards for topping-cycle cogeneration facilities.*

In its Notice of Proposed Rulemaking, the Commission recognized the problem of distinguishing cogeneration facilities which achieve meaningful energy conservation from those which are merely "token" facilities, producing trivial amounts of either useful heat or power. In the proposed rules, the *bona fide* character of a facility was to be determined by minimum amounts of useful heat and power output.

The need for operating standards as a means of identifying *bona fide* cogeneration facilities drew considerable comment. Some comments indicated that this formulation had the effect of imposing energy efficiency requirements which are not appropriate for some technologies. Commenters stated that a much simpler test than the proposed standards would be adequate for the task. Two commenters suggested a simple test regarding the portion of energy developed in the form of useful heat or steam. One potential qualifying facility [14] suggested that:

> for geothermal energy cogeneration facilities, the energy utilization by the non-electric processes must average on an annual basis at least 5 percent of the energy consumption of the heat engine.

Another commenter suggested "a minimum of 10% of the total steam generation must be used as steam send-out." [15]

Generally, commenters did not oppose a requirement for distinguishing a *bona fide* cogeneration facility from essentially single purpose facilities, even while taking exception to the form and substance of the proposed efficiency standards. One commenter [16] stated:

> A significant portion of the steam, heat or energy available from the cogeneration unit should be used in an industrial, commercial, heating or cooling applications. The concept of an operator of a large thermal generating station applying condensing techniques taking a tiny side stream out to heat a tool shed so that cogeneration could be claimed should be prohibited.

The Department of Energy [17] recommended the inclusion of a requirement that some minimal fractions of useful heat and power be produced.

Consequently, the Commission has decided that a simple means of identifying *bona fide* cogeneration facilities is appropriate. The *bona fide* test has been modified to specify only that a minimum proportion of the useful energy output be useful thermal energy output without regard to the energy input. The standard requires that at least 5 percent of a qualifying cogeneration facility's total energy output be in the form of useful thermal energy output. Compliance with this standard is to be based on estimated annual energy output.

Further, this basic *bona fide* test is applicable only to topping-cycle facilities. "Tokenism" is of concern for bottoming-cycle facilities chiefly with regard to the opportunity for qualifying facilities to obtain exemption from incremental pricing under the Natural

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[14] Republic Geothermal, Inc.

[15] Raytheon Corporation.

[16] This commenter, Potlatch Corporation, proposed as a test that at least 25 percent of the steam, or useful energy, available be applied on an annual basis in industrial, commercial, heating or cooling uses.

[17] The Economic Regulatory Administration.

Gas Policy Act. Natural gas used by bottoming-cycle facilities (other than in supplementary firing), will, as a general matter, be exempt from incremental pricing only to the extent that reject heat is utilized in power production. In view of these provisions, no separate *bona fide* test is necessary.

§ 292.205(a)(2)(i) Efficiency standards for topping-cycle facilities.

The proposed rules set forth efficiency standards for oil- and gas-fired topping-cycle cogeneration facilities. The efficiency standards were composed of three separate criteria. The first criterion required, in effect, that no less than 20 percent of the energy input to the facility be converted to mechanical or electrical power. The second criterion specified that 45 percent of the heat rejected from the heat engine (a term used in the proposed rule to describe the power production process) be put to use in a thermal process. The final criterion required at least 60 percent of the energy input to the facility be used either as power or useful heat.

Comments on the proposed efficiency standards criticized both their form and substance. Many commenters stated that the 20 percent efficiency criterion for heat engines was overly restrictive. These commenters pointed out that most steam turbines would not be able to meet the standard with conventional steam inlet and exhaust pressures. Many such steam turbine cogeneration systems would represent energy efficient systems when compared to the standard practice of separate steam and electricity production.

Fewer comments were directed toward the efficiency tests concerning heat recovery and overall efficiency. The comments that were made, however, indicated a need for revision. One commenter indicated that the heat recovery standard would exclude diesel-powered cogeneration facilities even though many such facilities would be highly energy efficient. Comments on the overall efficiency standards were mixed. One commenter suggested that the standard was too lenient. Another commenter recommended that the proposed 60 percent test be reduced to 50 percent, although this commenter appeared to be principally concerned with the application of efficiency standards to the use of renewable resources and not to the use of scarce fuels.

Five commenters addressed the question of efficiency standards for oil- and natural gas-fired cogeneration in a comprehensive manner by proposing a complete set of alternative standards. Four of these five commenters advanced proposals based on energy balance criteria, similar in theory to the proposed standards. A proposal by the New York State Energy Office closely resembled the proposed rule. Under this plan, individual tests for heat engine efficiency, heat recovery, and overall efficiency would still be required. The overall efficiency test would remain at 60 percent, but the heat engine and heat recovery tests would be reduced to 10 percent. This was the only comment in favor of maintaining separate efficiency standards for power production and heat recovery. The criticism of that scheme has caused the Commission to adopt an alternative efficiency standard which better takes into account the variety of technologies which qualify under this rule. The essential issue concerns the proper level of the overall efficiency standard which should be applied in individual cases.

Three commenters proposed efficiency standards relating solely to overall efficiency. A utility[18] recommended a single standard of 50 percent overall efficiency, which was the most lenient standard suggested. This proposal, furthermore, would be related to design efficiency and not actual or estimated operating efficiency. Another commenter[19] recommended a single standard of 65 percent overall efficiency. This standard would be slightly stricter than the first proposal discussed for all facilities except those producing predominantly either electricity or heat. Finally, the Commonwealth of Massachusetts Office of Energy Resources proposed a standard which would weigh thermal energy with only half the value of electricity.

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[18] Brooklyn Union Gas Company.

[19] Mechanial Technology Incorporated.

The latter two comments are both supported by well-reasoned examples of cogeneration engineering practice. The Massachusetts proposal is relatively more stringent for facilities producing more heat than electricity, and more lenient for facilities producing much of their output as electricity. The basis for this proposal is a comparison of cogeneration systems based on steam turbine, combustion turbine, and diesel engine prime movers with oil-burning non-cogeneration technology. Essentially, it is argued that any cogeneration facility meeting the proposed efficiency standard will be more efficient than any combination of separately generated electricity and steam using efficient, state-of-the-art technology. By requiring that the sum of useful power output and one-half the useful thermal output be greater than 45 percent of the facility's energy consumption, this proposal would ensure that qualifying facilities produce heat and power more efficiently than a 8500 Btu/kWh combined cycle generating station and a 90 percent efficient process steam boiler.

Moreover, this proposal appears to impact the various cogeneration technologies more equitably than the other proposed standards. The other proposals for required overall efficiency, by simply summing heat and power on an equal basis, make qualification relatively easy for steam turbine systems which produce little electricity. Cogeneration systems which produce high ratios of electricity to heat would be penalized with difficult heat recovery requirements. Yet the systems with high electricity to heat ratios have the highest "second law" energy efficiencies. Futhermore, a standard which is relatively lenient towards oil- and natural gas-fired steam cogeneration would encourage boiler fuel use of distillate oil and natural gas.

The proposal of another commenter, although considered in detail, would impact different cogeneration technologies differently and would not give assurance of energy conservation.[30]

In light of the foregoing considerations, the Commission has decided to adopt a standard in paragraph (a)(2)(i) similar to that proposed by the Massachusetts Office of Energy Resources as its standard for efficiency of new oil- and natural gas-fired topping-cycle cogeneration systems. This standard requires that for any topping-cycle cogeneration facility for which any of the energy input is natural gas or oil and the installation of which began on or after March 13, 1980,[31] the useful power output plus one-half the useful thermal energy output of the facility must be, during any calendar year, no less than 42.5 percent of the energy input of natural gas and oil to the facility. The Commission adopted a value of 42.5 percent, rather than the 45 percent recommended by the

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[30] The efficiency standard proposed by this commenter, the American Paper Institute, differed from all others fundamentally in that an effective heat rate test was required. A qualifying cogeneration facility was defined as:

A cogeneration facility that for the electric energy produced incrementally to steam or useful energy production:

1. Uses less that 9,000 BTU of additional fuel per kilowatt hour and

2. Produces more electric energy than it consumes

And that at least twenty-five percent of the steam, or useful energy, available is applied on an annual basis in industrial, commercial, heating or cooling uses.

[31] The preamble discusses new versus existing facilities. This is expressed in the regulations as "facilities, the installation of which began on or after March 13, 1980," or before that date. The Commission views the beginning of installation as the beginning of physical modification of the site or of pre-existing facilities. Of course, any sharp line will create its own inequities and raise its own questions. The waiver provision of § 292.205(d) is available to redress those inequities, and the optional procedure for qualification under § 292.207(b) is available to answer those questions.

Massachusetts comments because, in the Commission's view, the 45 percent requirement appears overly restrictive for steam turbine cogeneration facilities in that very high boiler efficiencies would have been required. However, if the useful thermal energy output of any such facility is less than 15 percent of its total energy output, the useful power output plus one-half the useful thermal energy output of the facility must be no less than 45 percent of the total energy input of natural gas and oil to the facility.

Existing Versus New Cogeneration Facilities

Although the Commission has found a compelling reason to impose efficiency standards on new oil and gas burning cogeneration facilities, the situation with respect to existing facilities is different. Existing facilities are those for which the installation of the cogeneration equipment began before the Commission actions encouraging cogeneration under this program were finalized. Presumably, such facilities would continue to be installed or operated using whatever fuels they are equipped to burn, with or without the incentives of PURPA.

Allowing existing facilities to qualify will provide for more flexible operation of the facilities. Optimum efficiency of a cogeneration facility may be more easily approached through interconnected operation with an electric utility. Because of the foregoing considerations, denial of qualifying status would serve no useful purpose.

Existing cogeneration facilities burning oil or natural gas were, in large measure, installed in an environment of lower fuel prices. Such facilities may not be able to meet the higher standards now reasonable for use of scarce fuels. Yet failure to meet standards intended for new facilities should not preclude entitlement to sell power to the utility and to receive the other rate benefits, as provided under Subpart C of these rules. In addition, the denial of exemption from regulation as an electric utility may discourage cogeneration at existing facilities.

The Commission has decided against imposing any efficiency standards on existing facilities, regardless of energy source. There is no assurance that imposing standards would result in fuel savings. The opposite result is more likely, if operating cogeneration facilities are denied the benefits of interconnected operation with an electric utility. Therefore, for any cogeneration facility, the installation of which began before the date the Commission's final rules in this docket were issued, March 13, 1980, no efficiency standards are required for qualification, regardless of energy source or whether it is a topping or bottoming-cycle facility.

Efficiency To Be Based Upon Projected Annual Operation

Several commenters raised the issue of whether efficiency calculations should be based on rated performance characteristics or on expected performance over a period of time. Only half of the commenters that mentioned the issue took a position in favor of one means of computation or another. The balance of the commenters merely asked for clarification.

The Commission is persuaded that the efficiency of a cogeneration facility operating at peak production of power and heat may not necessarily correlate with the efficiency which can be practically realized. A cogeneration facility which serves a highly variable heating load may seldom be operated at peak efficiency. The efficiency standards required for new oil or natural gas cogeneration facilities are intended to assure efficient use of these premium fuels. Use of optimum or design basis circumstances for determining efficiency would not satisfy the Commission's concern. A computation based upon projected or estimated annual operations will more closely reflect the facility's actual energy conservation potential.

The Commission realizes that estimates will be required in order to determine the efficiency of a facility not yet constructed. The Commission believes, however, that such estimates would routinely be performed prior to any decision to invest in cogeneration equipment. No significant burden is therefore expected in determining a cogeneration facility's qualifying status.

Why the Efficiency Standard Based on "Effective Heat Rates" Was Not Adopted

Evaluating the performance of a cogeneration facility in terms of the quantity of additional fuel used per kilowatt hour of electricity generated, above that needed for heating purposes alone, results in a standard known as the "effective heat rate".[22] This form of efficiency evaluation has been widely used to compare cogeneration of electricity to conventional utility generation. For a typical backpressure steam turbine cogeneration facility the effective heat rate of electricity generation may be as low as 4500 BTU/kWh—twice the efficiency of central station utility generation.

The effective heat rate test has some serious drawbacks, however. The test looks only to the efficiency of electricity generation and ignores the balance of the cogeneration facility. While the effective heat rate of a topping turbine may be high, if only a small fraction of the energy produced is in the form of electricity, the overall system is essentially a boiler facility, and the aggregate energy conserved is minimal. Indeed, effective heat rates are most favorable for systems which produce little electricity and a large amount of steam. The effective heat rate is lower for combustion turbine and internal combustion cogeneration, as compared to steam, but such systems produce more electricity per unit of fuel used. When the efficiency of the entire system is computed in such a manner as to credit the quality as well as quantity of energy produced,[23] combustion turbine or internal combustion cogeneration systems consistently score higher than steam systems. Thus the effective heat rate test does not truly measure overall system efficiency, and is not an adequate measure of whether, in the aggregate, energy is conserved through cogeneration.

§ 292.205(a)(2)(ii) Topping-cycle facilities using energy sources other than oil or natural gas.

In the final rule, the Commission has decided not to impose efficiency standards for qualification of topping-cycle cogeneration facilities using energy sources other than oil or natural gas. The proposed rules contained standards for topping-cycle cogeneration facilities using energy sources other than coal or coal-derived fuels. The efficiency standards were proposed in response to two concerns. First, some energy sources may be viewed as limited in access. Use of such resources by one cogenerator deprives another, possibly more efficient cogeneration facility, of the opportunity to use the resource. Efficiency standards were proposed in order to ensure that the first cogenerator, to gain access to the resource, would build an efficient facility in the absence of an effective market for the resource.

The second concern dealt with a means of distinguishing a *bona fide* cogeneration facility from a small power production facility with incidental recovery and use of steam or heat. The Commission believed that some means was necessary to prevent small power production facilities from evading the statutory size limits. A standard setting forth minimum production of power and minimum recovery of heat was seen as a means of avoiding the qualification of "token" cogeneration facilities.

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[22] To compute a cogeneration facility's effective heat rate, an assumption is made that the thermal output of the facility would have to be supplied in any event. A certain quantity of fuel would be needed to satisfy the thermal load in the absence of cogeneration. For example, if a steam turbine topping-cycle cogeneration facility were not installed, a conventional steam boiler would raise the steam. With the topping-cycle system, slightly more fuel is burned to raise steam at a higher pressure than is needed for the thermal process. The steam is expanded in a turbine, generating electricity and exhausting steam at the proper pressure for the thermal process. Effective heat rate is computed by dividing the extra energy supplied to the facility by the electricity generated.

[23] A Btu of electricity, for example, is worth more than a Btu of low pressure steam. The steam may be used for heat, but it is not useful for lighting or operating a television set. The "Second Law Efficiency" concept accurately reflects the usefulness of various forms of energy.

Neither concern is, however, relevant to the use of coal as a primary fuel. Coal is not characterized by limited access and it cannot be used as a primary fuel by small power production facilities. Therefore, the proposed rule contained no efficiency standards for facilities fueled by coal.

Most commenters addressing this question stated that the proposed standards were impossible to meet in many instances. More importantly, commenters questioned the basic rationale of applying efficiency standards. The limited access concept is complex, and some commenters missed the point, arguing that such resources are renewable or available in large quantity.

EPA pointed out that the degree to which limited access may affect the sort of facility constructed is unknown. The effects of limited access, if any, are likely to be site specific, and will vary with time. Even if these effects could be spelled out with certainty, the specification of appropriate efficiency criteria would be a difficult task at best. If a standard of thermal efficiency were set without detailed knowledge of both the technologies and patterns of resource development, the probable effect would simply be to stifle development of the resource.

The Commission concludes that the proposed cure is far worse than the suspected ailment. In addition, as was stated in the discussion addressing the operating standards, the 5 percent minimum amount of useful thermal output standard will assure that these facilities are *bona fide* cogenerators under these rules.

§ 292.205(b) Efficiency standards for bottoming-cycle facilities.

The proposed rule contained a two-part efficiency standard for bottoming-cycle cogeneration facilities. All facilities, except those using coal or coal-derived fuels, would have been required to meet the standards. The first part of the efficiency standard dealt with the heat engine. In order to qualify, a facility had to either convert 15 percent of the reject heat from the thermal process to mechanical energy, or in the alternative, achieve 40 percent of the ideal Carnot efficiency with the working fluid temperatures experienced. The second part of the standard simply required an overall energy efficiency of 60 percent for the entire facility.

Numerous commenters were critical of the proposed standards. Although a number of issues were addressed, a common concern was the counter-productive nature of efficiency standards for bottoming-cycle cogeneration facilities relying on reject heat. It was argued that because the heat would otherwise be wasted, efficiency standards would serve no fuel conservation purpose. The only effect of efficiency standards would be a limitation on the number of bottoming-cycle facilities which would be constructed.

Moreover, many commenters noted that the overall energy efficiency standard of 60 percent was overly restrictive, and in fact meaningless in many instances. The overall energy efficiency, as defined in the proposed rule, would be determined by the efficiency of the bottoming-cycle heat engine and the efficiency of the industrial thermal process. Typically the latter efficiency is predetermined by the nature of the process and the design of the industrial plant. When bottoming-cycle cogeneration equipment is added to an existing plant, the efficiency of that plant's energy utilization is irrelevant to the effectiveness of the bottoming cycle. Furthermore, the measurement of overall energy efficiency required under the proposed rules would be difficult, since such efficiency measurements are not a conventional practice.

The Commission recognizes the validity of these comments, and has therefore eliminated efficiency standards for most bottoming-cycle cogeneration facilities. The final rule contains an efficiency standard for only those facilities with oil or natural gas supplementary firing. The need for standards in this case was acknowledged by several commenters.

When supplementary firing is used in a bottoming-cycle cogeneration facility, more than reject heat is used to generate electricity. Scarce fossil fuels can be introduced without the inherent efficiency advantages of sequential use. In order to restrict the potential for abuse, the Commission has adopted a simple efficiency test similar to that suggested by one of the commenters. The standard relates only to facilities installation [24] of which began on or after March 13, 1980, and for which any of the energy input as supplementary firing is oil or natural gas. Paragraph (b)(1) specifies that the useful power output of the bottoming cycle must, during any calendar year, be no less than 45 percent of the energy input of natural gas and oil for supplementary firing. The Commission notes that the fuels used in the thermal process "upstream" from the bottoming-cycle facility's power production system are not considered in this efficiency test. The use of the lower heating value, consistent with the proposed rules, is advantageous to cogenerators in that the latent heat of combustion water cannot be effectively recovered by any practical bottoming-cycle technology currently foreseeable.

§ *292.205(c) Exemption from incremental pricing.*

One of the incentives for cogeneration is found not in PURPA but in the Natural Gas Policy Act of 1978 (NGPA). In section 206(c), the Commission is given the discretion to exempt qualifying cogeneration facilities from its incremental pricing program developed under Title II of the NGPA.

On September 28, 1979, the Commission issued final rules implementing the incremental pricing provisions of the Natural Gas Policy Act of 1978.[25] These rules provide, among other things, that natural gas used by "a qualifying cogeneration facility" shall be exempt from the incremental pricing provisions of the NGPA.[26] A qualifying cogeneration facility is defined in the regulations as a cogeneration facility which meets the requirements prescribed by the Commission pursuant to section 201 of the Public Utility Regulatory Policies Act of 1978 (PURPA).[27]

In this paragraph, the Commission has set forth the requirements for exemption from incremental pricing. Paragraph (c)(1) allows that any topping-cycle cogeneration facility which is a qualifying facility under § 292.203(b), and, if not already required to do so, meets the operating and efficiency standards under paragraphs (a)(1) and (2)(i) of this section, or is a qualifying facility under Subpart E of this part, may obtain an exemption from incremental pricing for its natural gas use.

Paragraph (c)(2) enables natural gas used in bottoming-cycle cogeneration facilities and which is not exempt from incremental pricing under Subpart E of this part to obtain exemption under this subpart to the extent that reject heat emerging from the useful thermal energy process is made available for use for power production. The Commission feels that these requirements adequately reflect the goal of PURPA to encourage the efficient use of energy by cogeneration facilities. To the extent that a facility makes available its reject thermal energy to produce power, the Commission believes it should obtain the benefit of exemption from incremental pricing.

The Commission does not intend for this subpart to interfere with any exemptions provided under Subpart E. Therefore, paragraph (c)(3) provides that any person who obtained an exemption under Subpart E is not affected by this provision.

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[24] In the case of bottoming-cycle cogeneration in which electric generating equipment is retrofitted to existing sources of industrial reject heat, the date at which installation begins is the date on which the retrofit is begun.

[25] 18 CFR Part 282, 44 FR 57226 (Oct. 5, 1979).

[26] 18 CFR 282.201(a).

[27] 18 CFR 282.202(e).

Paragraph (c)(4) provides that natural gas used for supplementary firing in any cogeneration facility is not eligible for exemption from incremental pricing under this subpart. However, natural gas used for supplementary firing of a bottoming-cycle facility would be exempted under the Commission's Order No. 49–A, to the extent that the facility generates electricity which is sold to a utility.[28]

When the final regulations under Phase II of incremental pricing take effect and the Commission can then better assess their implications, the Commission may wish to revise the exemptions from incremental pricing to cogeneration facilities, including the exemption provided in the Interim Rule under Subpart E.

§ *292.205(d) Waiver.*

This paragraph provides that the Commission will consider waiving any of the standards described above upon a showing that the facility will produce significant energy savings.

§ *292.206 Ownership criteria.*

Section 292.206 is designed to implement the statutory requirement that a qualifying small power production facility or cogeneration facility must be owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities). Regarding this provision, the Commission notes that the Conference Report states that:

> [e]lectric utilities may participate in an entity which owns such (qualifying small power production or cogeneration) facilities with other persons, and such entity could qualify under these definitions.
>
> The test of this case is whether the entity which owns the facility is primarily engaged in the generation or sale of electric power other than in connection with its ownership of the cogeneration facilities or small power production facilities.[29]

Thus, either directly or through a subsidiary company, an electric utility could participate in the ownership of a qualifying cogeneration or small power production facility.

Several commenters noted that under a literal interpretation of the Conference Report's statement, several electric utilities could form a subsidiary which owned small power production or cogeneration facilities. Such a subsidiary would constitute an entity which is not primarily engaged in the generation or sale of electric power other than in connection with its ownership of cogeneration or small power production facilities. Under such an interpretation, the subject facilities would be eligible to receive qualifying status.

The Commission believes, however, that the thrust of section 201 of PURPA is to limit the advantages of qualifying status to cogeneration and small power production facilities which are not owned primarily by electric utilities or their subsidiaries. The proposed rule provided that if, based on the proportion of ownership by electric utilities, public utility holding companies, or subsidiaries of either, more than 50 percent of the entity which owns the cogeneration or small power production facility is comprised of these electric utility interests, then the facilities are not qualifying facilities. This language has been incorporated into these final rules; the comments on this section provided no sufficient reasons in the Commission's judgment for changing the percentage.

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[28] See Order No. 49–A, issued December 27, 1979, in Docket No. RM79–14, 45 FR 21 (Jan. 2, 1980).

[29] Conference Report on H.R. 4018, Public Utility Regulatory Policies Act of 1978, H. Rep. No. 1750, 89, 95th Cong., 2d Sess. (1978).

The Commission emphasizes the fact that nothing in this program limits the extent of utility ownership or operation of cogeneration or small power production facilities. The Commission notes the statement in the Conference Report that:

> . . . it is also the intention of the conferees that the definition of "qualifying cogeneration facility" and "qualifying small power production facility" will not be construed as prohibiting or discouraging electric utilities from cogenerating.[30]

Utilities may not, however, qualify for the benefits under this program if their ownership interests exceed the limits set forth in this rule.

Both the provisions in section 3(17)(C)(ii) and 3(18)(B)(ii) of the Federal Power Act, as amended by section 201 of PURPA, use the term person in describing who may own a qualifying cogeneration facility and qualifying small power production facility. The Commission has incorporated the ownership criteria under this section of the regulations and has used the term—person—found in the statute.

A few commenters questioned whether a municipality (or any other agency or instrumentality of State or Federal government) falls within the definition of the term "person" as used in definitions (17) and (18) in section 3 of the Federal Power Act. It is the Commission's view that the term "person," for purposes of qualifying under this program, does include municipalities (or any other agency or instrumentality of State or Federal government). This view is supported by case law in which the courts have treated municipalities and other units of State and Federal government as persons under other sections of the Federal Power Act. *See, e.g., United States v. Public Utilities Commission of California*, 345 U.S. 295 (1953); and *New England Power Co. v. FPC*, 349 F.2d 258 (1st Cir. 1965). The cases touching on the issue of these agencies as persons are very expansive (see the *California Public Utility Commission* decision cited above which was decided by the Supreme Court in 1953). Therefore, under past practice, the Commission and the courts have not interpreted "person" to exclude a municipality or other unit of State and Federal government from the benefits of any action of the Federal Power Act.

In addition, in that there is no indication that the Congress meant to deny qualification to these agencies or instrumentalities, the Commission finds no policy grounds for denying these agencies or instrumentalities qualifying status. Therefore, both as a matter of law and as a matter of policy, the term "person" as used in section 3(17)(C)(ii) and 3(18)(B)(ii) includes these agencies or instrumentalities. The effect of this is to allow these agencies or instrumentalities the opportunity to participate in this program if they otherwise meet the standards for qualification set out in this subpart.

§ *292.207 Procedures for obtaining qualifying status.*

This section sets forth the procedures for obtaining qualifying status. Paragraph (a)(1) provides that a small power production facility which meets the criteria for qualification set forth in § 292.203 is a qualifying facility. As discussed above, the Commission has eliminated the mandatory case-by-case qualification procedure contained in the proposed rule.

Paragraph (a)(2) requires any owner or operator of a facility qualifying under paragraph (a)(1) to furnish notice to the Commission. The contents of the notice shall contain the information required of an applicant for qualifying status in paragraph (b)(2)(i) through (b)(2)(iv) described below. The Commission is requiring such notice for purposes of monitoring the market penetration of qualifying facilities, in compliance with its responsibilities under the National

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[30] Conference Report on H.R. 4018, Public Utility Regulatory Policies Act of 1978, H. Rep. No. 1750, 89-90, 95th Cong., 2d Sess. (1978).

Environmental Policy Act of 1969, as previously discussed in this preamble.

Paragraph (b) provides an optional procedure whereby the owner or operator of a small power production facility may, should it prove desirable, file an application with this Commission for certification that the facility or cogeneration facility is a qualifying facility. The application must contain enough information to enable the Commission to make an accurate finding that the facility should or should not be certified.

Specifically, paragraph (b)(i) through (v) provides that each application must contain the name and address of the applicant and the location of the facility, a brief description of the facility including a statement indicating whether such facility is a small power production facility or a cogeneration facility, the primary energy source used or to be used by the facility, the rated power production capacity of the facility, and the percentage of ownership by electric utilities, or public utility holding companies, or by any person owned by either.

Applications by owners or operators of small power production facilities must also contain the location of the facility in relation to any other small power production facilities within one mile of the facility owned by the applicant which use the same energy resources, and information identifying any planned usage of natural gas, oil or coal.

An application by a cogenerator must contain the date installation facility commenced, a description of the cogeneration of the facility, including whether the facility is a topping or bottoming cycle, and sufficient information to determine that any applicable efficiency or operating requirements have been met.

Paragraph (b)(5) sets forth the procedures to be used by the Commission to determine whether a facility is to be granted qualifying status. It provides that, within 90 days of the filing of a complete application, the Commission shall issue an order granting or denying the application, extending the time for issuance of an order, or setting the matter for hearing. If no order is issued within 90 days of the filing of the application, it shall be deemed to have been granted.

The Commission will rely on its existing procedures for any person to file a petition for reconsideration of any Commission action instead of employing the protest procedure contained in the proposed rule.

Several commenters, while offering support for the elimination of filing and notice requirements for smaller facilities, acknowledged the useful purpose that would be served by a requirement that a larger facility give notice to the affected utility of its qualifying status and its intention that such utility purchase its power. Accordingly, the Commission has provided a requirement in paragraph (c) that an electric utility is not required to purchase electric energy from a facility with a design capacity of 500 kilowatts or more until 90 days after the facility notifies the utility that it is a qualifying facility, or 90 days after the facility has applied to the Commission under paragraph (b).

Paragraph (d)(1) provides that the Commission may revoke the qualifying status of a facility if it ceases to comply with any of the statements contained in its application for Commission certification. The Commission may do so on its own motion, or upon a motion to reconsider any certification previously granted. In either case, the Commission will act only after providing an opportunity for a hearing. Paragraph (d)(2) provides that, prior to undertaking any substantial alteration of a qualifying facility, a small power producer or cogenerator may, should it prove desirable, apply to the Commission for a determination that the facility, as modified, will retain its qualifying status.

IV. Effective Date

The Conference Report indicates that rules respecting criteria for qualifying facilities be prescribed "as soon as practicable" in order that persons may ascertain in advance of construction or operation of any facility whether or not such facility will meet the criteria established. The Commission believes, therefore, that good cause exists under 5 U.S.C. 553(d) to make the rules promulgated in this order effective immediately.

These rules have been promulgated under the Federal Power Act, as amended by PURPA, and, therefore, a right to rehearing exists under section 313 of the Federal Power Act.

(Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601, *et seq.*, Energy Supply and Environmental Coordination Act, (15 U.S.C. 791 *et seq.*), Federal Power Act, as amended, 16 U.S.C. 792 *et seq.*, Department of Energy Organization Act, (42 U.S.C. 7101 *et seq.*), E.O. 12009, 42 FR 46267, Natural Gas Policy Act of 1978, (15 U.S.C. 3301, *et seq.*))

In consideration of the foregoing, the Commission amends Part 292 of Chapter I, Title 18, Code of Federal Regulations, as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

Appendix I

Note.—This Appendix should not be included in the text of the regulations in the Code of Federal Regulations.

Summary of Comments on Preliminary Environmental Assessment

General. Numerous comments addressed the Environmental Assessment in general and discuss the need for a programmatic environmental impact statement (EIS).

Some of the comments favored an environmental impact statement. The New England Chapter of the Sierra Club stated that it is in accord with the general thrust of the Environmental Assessment. However, it is concerned with the encouragement of those technologies which utilize non-renewable energy resources and with those technologies which, if uncontrolled, tend to produce large quantities of pollutants. Therefore, the commenter stated that a generic EIS is needed to examine the absolute environmental effects of the rulemaking in encouraging all the assumed "benign" technologies.

This commenter also concurred with the suggestion that, pending issuance of a generic environmental impact statement, the Commission should proceed with the implementation of rules and regulations under sections 201 and 210 of PURPA, except for technologies which may result in significant impacts as a result of the rules. For these technologies, the comments recommended that the Commission should proceed promptly to produce a comprehensive generic environmental impact statement.

Southern Company Services suggested that while the requirement to file an environmental impact statement may temporarily discourage cogeneration or small power production, it appears to be the only procedure for determining the environmental acceptability of a qualifying facility.

The Solar Lobby endorsed preparation of an EIS only where the environmental consequences of a qualifying facility are clearly negative. This commenter recommended that the more benign technologies should be encouraged even while appropriate generic environmental impact studies are performed.

Arthur D. Nadler Associates added that the environmental impact statement requirements should be kept to a minimum and be consistent with the small size of the facilities generally associated with those technologies.

Other commenters are opposed to the idea of a generic EIS. The California Energy Commission argued that the Commission's Environmental Assessment is adequate and that an EIS should not be required, particularly since any individual qualifying facility will receive State and Federal environmental scrutiny before it is constructed.

The California Energy Commission also suggested that the delay in adopting these regulations while an EIS is prepared and issued would itself cause adverse environmental and socioeconomic effects. Arizona Public Service Company and Brooklyn Union Gas Company concurred with the thrust of California's comment that, "Qualifying facilities will be delayed or not developed if the regulations are not adopted immediately. The failure to develop these qualifying facilities in a timely fashion will result in increased air pollution and adverse socioeconomic impacts from the increased consumption of imported oil and other fossil fuels during the period until the regulations are issued."

The Missouri Public Service Commission stated that for residential cogenerators or small power production facilities, an environmental impact statement will work as a disincentive, hindering consumer efforts at alleviating the energy problem. This commenter noted that while section 201 and 210 rules do have an effect on the quality of the human environment, it is a very beneficial one in that this program offers some viable alternatives for easing the energy problem. "As little interference by government with its agencies should be the goal so that American ingenuity and know-how can flourish."

Pan Tech Management stated that the PURPA rules will not constitute an action that will significantly affect the environment. This commenter recommended that the Commission promulgate the proposed rule with appropriate modifications based on public comment, but that it should not withhold promulgation of any part of the rules pending preparation of an EIS. The Commission should, in this commenter's view, review case-by-case, certain locations where environmental quality may already be below the standard (i.e. non-attainment areas with regard to air quality criteria), thus precluding the implementation of certain technologies.

The Colorado Office of Energy Conservation suggested that a much more critical need than an EIS for small power producers is a social and economic impact analysis.

Cogeneration technologies and their environmental impacts.

With regard to cogeneration, the commenters generally suggested that diesel cogeneration in congested urban areas may have adverse air quality effects.

Consolidated Edison, Boston Edison and Union Electric and separate comments by Southern Company Services stated that the proliferation of relatively small diesel cogeneration units installed in residential and commercial buildings would significantly affect the environment. The joint comments noted that each individual unit would likely escape any meaningful environmental review by State and Federal environmental authorities under current regulations, and yet the cumulative impact could well be serious. It was asserted that the problem will be particularly acute in areas where the attainment of national ambient air standards already is marginal (most congested urban areas), and where increases in pollutant concentrations would restrict opportunity for urban development and economic recovery. It was further asserted that most of the cogeneration is likely to be diesel engines, which these commenters stated emit larger amounts of some critical pollutants, per unit of energy produced, than do properly designed central power station plants. The joint comments stressed that cogeneration facilities discharge pollutants in non-buoyant plumes at roof-top levels which it was claimed will cause far greater pollution concentrations at street levels where people live and breathe, than do the buoyant plumes from the high, free-standing stacks of powerplants.

One of the commenters, Consolidated Edison, stated that on-site electric generation using diesel engines with waste heat recovery systems is already an economic alternative to its electric service or, in some cases, a combination of its electric and steam services, for some 395 customers representing a combined peak load of more than 1,000 MW. As additional incentives are added to the already favorable tax and regulatory climate for cogeneration installations in its service area, the utility claimed that the potential for conversions from central station to on-site generation could increase.

Consolidated Edison cited several studies prepared at its request which indicated that nitrogen dioxide (NO_2) standards in Manhattan could be contravened with the addition of as little as 240 MW of diesel cogeneration facilities in that borough. Consolidated Edison also stated that the studies indicated that the primary annual air quality standard for sulfur dioxide (SO_2) will be exceeded after several hundred more megawatts of diesel cogeneration capacity are installed.

Thomas Casten, speaking on behalf of The Cogeneration Society of New York, criticized several assumptions used in the Consolidated Edison studies. First he stated that several of the cogeneration facilities which the studies assumed would be installed in New York City violate existing environmental laws, and, therefore would not be installed. Secondly, he stated that these studies assume that 75 percent of the cogeneration plants would be installed in Manhattan, where environmental impacts would be most severe. He noted that eighteen of nineteen existing cogeneration plants in New York city are located outside of Manhattan.

This commenter next criticized the assumption that more than one thousand megawatts of diesel cogeneration will be installed in the New York City area, on the basis that this figure seems to exaggerate greatly the likely amount of cogeneration capacity. In addition, he contended that the standards used for measuring the emissions were those used for truck and bus-type engines which operate at varying speeds. He stated that a typical diesel cogeneration facility would operate at a fairly constant speed; and that, at constant speeds, emissions are about one-fourth of those produced at varying speeds.

Finally, the commenter noted that these studies assumed that there would be no improvements in the environment resulting from other factors during the time that the one thousand megawatts of diesel cogeneration were projected to be installed in New York City.

Commonwealth Edison and Consolidated Edison suggested that noise produced by diesel engines is a very serious environmental impact, and that the impact in any specific area is independent of the total number of units in any region. These commenters recommended that an environmental noise impact assessment be prepared and the appropriate noise abatement measures be included in the on-site diesel-engine installations. This could be done, they asserted, by requiring potential cogeneration facilities to prepare a noise emission analysis showing that the emissions would not contravene local or State requirements.

Consolidated Edison, Boston Edison, Union Electric and Southern Company Services, Inc. recommended that in light of the serious environmental consequences which are likely to flow from these rules, it is incumbent upon the Commission to accompany its proposed rules with a draft environmental impact statement.

Furthermore, Consolidated Edison, Boston Edison, and Union Electric suggested that an environmental impact statement should be required with respect to each new cogeneration facility having the potential for a significant adverse impact on the environment. The comments stated that any proposed facility having a generating capacity of 500 kW or more would have such an impact and should require an EIS.

Brooklyn Union Gas Company surveyed eight companies with cogeneration facilities and concluded that no environmental problems have been associated with the operation of the facilities. The facilities obtained the required air emissions permits and have been operating in compliance with applicable air quality regulations.

Penti Aalto, a consultant, suggested that all types of cogeneration facilities be permitted without an EIS, subject to periodic review of the system as a whole. If problem areas appear, then appropriate action could be taken.

The New York State Public Service Commission proposed limiting qualifying status to suitable locations or limiting the density of qualifying facilities in any given area.

The New York State Energy Office stated that an EIS is not necessary at this time. It proposed as an alternative that the Commission consider imposing a direct limitation upon the density of diesel cogeneration in large populated urban areas since the preliminary EA concludes that the number and density of urban diesel cogenerators determines the environmental risk.

Small Power Production Facilities.

Solar Energy. The Colorado Solar Energy Association stated that nearly all solar electric options are far less damaging to the environment than fossil-fueled or nuclear electric generation. He noted that implementation of PURPA must not be delayed by requiring the preparation of lengthy and time consuming environmental impact statements for renewable energy based qualifying facilities.

Geothermal Energy. The New England Chapter of the Sierra Club suggested that geothermal power production using hot brine sources is acknowledged to pose problems of air and water pollution and a potential toxic waste disposal problem. This commenter recommended that since there are no immediate plans for small power plant construction using hot geothermal brine (it is their understanding that such power production is currently uneconomic), it seems unnecessary to promulgate rules to encourage its use prior to preparation of the generic EIS.

Small-Scale Hydropower. The State of Vermont—Agency of Environmental Conservation stated that the small hydro summary in the preliminary EA was incorrect in stating that instances are rare where there is significant impact from facilities being added to an existing dam. It was stated that as in the Bolton Falls project, or at Ball Mountain, the impact of development could be significant in terms of water quality, fishery habitat and production, recreation, and possibly aesthetics.

The New England Chapter of the Sierra Club suggested that run-of-river hydro installations suffer from the same siltation, turbidity, and biological oxygen demand problems as do generating capacity additions at existing dams. Because almost all new non-Federal hydroelectric projects must be licensed by the Commission and environmentally evaluated on a case-by-case basis, this commenter concurred with the promulgation of rules allowing qualification of small hydroelectric projects at existing dams. It was asserted that run-of-river hydroelectric projects, however, pose an additional problem: the potential for diversion of water from existing channels. Unless all run-of-river hydro projects are to be environmentally evaluated on case-by-case basis, this commenter recommended that qualifying status be withheld until after completion of the generic EIS.

Municipal Waste. Wheelabrator-Frye, Inc. stated that the encouragement of small power production and cogeneration fueled by municipal solid waste does not constitute a "major federal action significantly affecting the quality of the human environment." This commenter stated that small power production facilities which use such a feedstock produce a significant net *positive* impact on the overall environment since they reduce dependence upon highly polluting "open dumping" practices and encourage more efficient community solid waste management practices. He cited as an example one of the projects sponsored by his firm which has achieved waste volume reduction of more than 90 percent through currently available mass combustion technologies. He suggested that the quantity of waste requiring land disposal sites, as a result of processing through such facilities, is greatly reduced and more readily controlled and contained.

This commenter also suggested that since current EPA standards governing State implementation plans and new source performance procedures assure the conformance of such projects with the attainment of national air quality standards, no environmental impact statement need be filed by these facilities.

However, the New England Chapter of the Sierra Club stated that incineration of municipal wastes for power production purposes presents a potential problem in the emission of toxic substances, especially the more volatile heavy metals like mercury, cadmium and lead. With the eventual issuance of EPA regulations implementing the Toxic Substances Control Act, these emissions will be regulated; at this time they are not. This commenter does not propose an exception for municipal waste, but is concerned that any Commission regulations which encourage the incineration of municipal waste should insist on appropriate control technology.

Biomass. The New York State Energy Office and the Hawaiian Sugar Planter's Association stated that a detailed Environmental Assessment is not warranted for any of the biomass fuels already in use at small power production facilities.

The Hawaiian Sugar Planter's Association suggested that, in large part, the PURPA incentives should operate to encourage sugar factories to make more efficient use of the biomass already being burned and more efficient use of the steam being produced.

The New England Chapter of the Sierra Club stated that emission, soil tilth, fertility, and land use questions are present for biomass fuel. This commenter is concerned with the social effects of industrialization of agricultural areas induced by new biomass cogeneration facilities. "Biomass generally will provide relatively small amounts of net energy per unit mass or volume. As a result, encouragement of new biomass cogeneration facilities will tend to increase rural industrialization because high transportation costs will attract industrial cogenerators to the source of the biomass."

This commenter stated that it is not necessary to require an environmental impact statement for existing facilities or biomass cogeneration which use on-site produced waste—such as sawdust. However, it was suggested that an impact statement for new biomass-based cogeneration facilities which import off-site produced forest or agricultural products for the purpose of cogeneration should be required. "Cogeneration based on the use of stockyard wastes, kelp or similar sources need not be excepted if a thorough generic EIS is planned."

The Solar Energy Research Institute suggested that it is a mistake to group all types of "biomass" generating facilities together for environmental scrutiny. Many biomass systems use biogas in a combustion turbine and have minimal environmental impacts. This commenter recommended that several different classes of "biomass" facilities be identified and that each be considered separately.

The American Paper Institute stated that it was concerned that the Commission staff may not have taken into account many of the environmental benefits of burning wood and other biomass fuels.

Potlatch Corporation suggested that the definition of biomass in the preliminary environmental assessment is unusual and narrow. "Well-recognized concepts of biomass include all plant material including by-products of manufacturing, harvesting, and growing."

Wind. Two commenters suggested that the environmental effects of large wind energy conversion systems (WECS) can be significant. The State of Vermont—Agency of Environmental Conservation raised several problem areas. The first is that electromagnetic interference (as with radio or telecommunications) is an unknown quantity at the moment, with disagreement as to the extent of

disruption that will actually be caused by a large WECS.

The second problem discussed was road construction and site preparation, especially on the fragile areas such as sites above 2500 feet in elevation. The wind energy resource appears to exist predominately at these higher elevations, yet sites which may be desirable from a power point of view are fragile and easily disrupted. Loss of vegetation cover and erosion of soil are two of the main concerns.

A third problem raised by this commenter was that the noise pollution and visual impact of the WECS were not mentioned in the summary of the preliminary Environmental Assessment.

The Solar Energy Research Institute recommended that the environmental impacts of large wind machines may need more careful scrutiny than the preliminary EA acknowledged. It was asserted that difficulties with low frequency sound and land use impacts need careful attention.

[¶ 30,135]

45 F. R. 18915 (March 24, 1980)

18 CFR Part 271

[Docket No. RM80-44; Order No. 72]

Final Regulations Implementing Section 109 of the Natural Gas Policy Act of 1978

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) hereby reissues as final regulations its interim regulations implementing section 109 of the Natural Gas Policy Act of 1978 (NGPA). The primary purpose of the final rule is to resolve the central question of interpretation of section 109 by determining the proper scope of applicability of that section. In the final rule, the Commission reaffirms the interpretation of section 109 embodied in the interim regulations that section 109 applies only to first sales of natural gas not subject to a maximum lawful price under any other section of Title I of the NGPA.

EFFECTIVE DATE: March 18, 1980.

FOR FURTHER INFORMATION CONTACT:

Mark Magnuson, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Room 4016-I, Washingon, D.C. 20426, (202) 357-8511, or

Susan Tomasky, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Room 8100, Washington, D.C. 20426, (202) 357-8461.

Before Commissioners: Charles B. Curtis, Chairman; Georgiana Sheldon, Matthew Holden, Jr., and George R. Hall.

Issued: March 18, 1980.

I. Background

On December 1, 1978 the Commission issued interim regulations[1] implementing the Natural Gas Policy Act of 1978 (NGPA).[2] Under the interim regulations, the maximum lawful price established under section 109(b) is applicable to first sales of natural gas not subject to a maximum lawful price under sections 102, 103, 104, 105, 106, 107 or 108 of the NGPA.[3]

The interim regulation, which defines the scope of applicability of section 109, was based on the Commission's interpretation of the following language of section 109(a):

> **Sec. 109. Ceiling Price for Other Categories of Natural Gas.**
>
> **(a) Application—The maximum lawful price computed under subsection (b) shall apply to any first sale of any natural gas delivered during any month, in the case of any natural gas which is not covered by any**

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[1] 43 FR 56448 (Dec. 1, 1978).

[2] 15 U.S.C. 3301 *et seq.*

[3] 18 CFR 271.901

maximum lawful price under any other section of this subtitle, including—

(1) natural gas produced from any new well not otherwise qualifying for a higher maximum lawful price under this title; . . ." [paragraphs (2) through (4) omitted] [4]

As drafted, this language is ambiguous on its face. The language of section 109(a) which precedes paragraphs (1) through (4) appears to state a general rule of applicability which limits the scope of each of the four categories of specifically eligible (i.e., included) types of natural gas. However, listed among the four categories of gas specifically included within the scope of section 109 is "natural gas produced from any new well not otherwise qualifying for a higher maximum lawful price under this title," a category of gas that falls outside the general limitation of the preceding language.

Thus, section 109 is susceptible of two widely divergent interpretations. Read narrowly section 109(a) is intended to limit the scope of the categories which follow so that a new well which qualifies for a lower price under another section of the NGPA would be excluded from section 109. Read broadly, however, the specific categories are to be expressly included within the scope of section 109, superseding the preceding general limitation, so that a new well otherwise subject to a maximum lawful price lower than the section 109 price would nevertheless be eligible for the section 109 price.

In the interim regulation, the Commission took the view that the 109 ceiling price extended only to natural gas not qualifying for any other maximum lawful price established under Title I of the NGPA. A number of comments submitted in response to the interim regulation question that interpretation. Their objections are addressed below. For the reasons which are also set out more fully below, the Commission hereby affirms the position of the interim regulations, and adopts the interim regulation as the final regulation implementing section 109 of the NGPA.

II. Summary of Comments

Comments on the Commission's interpretation of section 109 concern, almost exclusively, its effect with regard to gas produced from new wells: in the Commission's view, natural gas from a well which qualifies for a lower maximum lawful price is ineligible for the higher price of section 109.

Objections to the Commission's interpretation rest on two grounds. Pennzoil, Tenneco, the Indicated Producers, Texaco, the Oklahoma Independent Petroleum Association (OIPA) and Exxon contend that the Commission's interpretation contravenes the language of the statute, by effectively ignoring the word "including" in section 109(a) as it pertains to the four categories described in clauses (1) through (4) of that section.

They argue that the Commission is obliged to follow the "plain meaning" of the word "including" which is "something as a constituent, component, or subordinate part of a larger whole" [5] or "comprising, comprehending or embracing as a component part, item or member; enclosing within or containing".[6] Applying this plain meaning, these commenters conclude that any natural gas which falls within the specific categories of clause (1) through (4) is expressly included within the scope of section 109. In contrast, they argue, the Commission's interpretation reads the word including to mean "might include, but not necessarily including".[7] The Commission's interpretation, it is claimed, effectively eliminates from the scope of section 109 all gas described in clauses (a)(1) through (4), by requiring that a producer seeking to qualify for a section 109 price would first have to establish that the gas is not covered by any other maximum lawful price.

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[4] NGPA, section 109(a)(1).

[5] Comment of OIPA.

[6] Comment of Exxon.

[7] Comment of Indicated Producers.

In addition to arguments based on the language of the statute, arguments were raised that the Commission's interpretation is contrary to Congressional intent as manifested in the Joint Explanatory Statement of the Committee on Conference (Joint Statement).[8] Grace Petroleum Corp., Texaco, the Interstate Natural Gas Association of America (INGAA), Panhandle Eastern Pipeline Co., Trunkline Gas Co., and Exxon point to language in the Joint Statement which states that section 109 applies to five enumerated categories of natural gas. Categories enumerated "(1)" through "(4)" in the Joint Statement are those categories described in clauses (1) through (4) of section 109 as drafted. Following these categories *in seriatum*, enumerated "(5)", is "any natural gas which is not covered by any maximum lawful price under any other section of this subtitle".[9] On the basis of this language, these commenters argue that Congress intended clause (1) of section 109(a) to enlarge, rather than to contract, the scope of applicability.

A comment submitted by Senator Pete V. Domenici agrees with the Commission that the language of section 109 is ambiguous on its face. However, it is his opinion that, despite the discrepancy between the language of the introductory clause and of clause (1), the intent of the Senate and House confereees was to apply the section 109(b) price to all new wells which didn't qualify for a higher price under another section.

The American Gas Association (AGA) voiced support of the Commission's interpretation of section 109(a). AGA argues that any other interpretation would negate the Congressional purpose in establishing the section 104 price, to retain the price ceiling (adjusted for inflation) applicable to interstate natural gas. They contend that if Congress had intended to price all gas supplies at a section 109 level or higher, it would have had no need to establish ceiling prices lower than the section 109 price. AGA further argues that any other interpretation of section 109 would render meaningless Section 121 of the NGPA. in 1984, Section 121 will deregulate intrastate gas subject to a contract price in excess of $1.00 per MMBtu; if all intrastate gas from new wells were subject to the 109 price of $1.45 per MMBtu, the eventual deregulation provided for under section 121 would accomplish the deregulation of virtually all intrastate gas produced from new wells.

III. Discussion

The crucial question of interpretation at issue here is the scope of applicability of section 109. Generally, the issue is whether section 109 is applicable to the four categories of natural gas described in clauses (1) through (4) of section 109(a) in addition to natural gas not covered by any other maximum lawful price, or is applicable only to natural gas not covered by any other maximum lawful price.

However, natural gas falling within the categories described in clauses (2) through (4) of section 109(a), in all cases, would not be subject to a maximum lawful price under another section, so that, as a practical matter, the issue is fundamentally narrower. Specifically, the issue is whether section 109 covers natural gas not covered by any maximum lawful price under any other section and natural gas produced from any new well not otherwise qualifying for a higher maximum lawful price under Title I, or only natural gas which is not covered by any maximum lawful price under any other section. Under the former interpretation, natural gas covered by sections 104, 105, or 106, could also qualify for section 109 if natural gas were produced from a new well. Under the latter interpretation, natural gas from a new well which is covered by section 104, 105, or 106 would be held to that applicable price, unless the gas qualifies for an incentive price under section 102, 103, 107 or 108.

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[8] S. Rep. No. 1126, 95th Cong., 2d Sess. (1978).

[9] The Joint Statement indicates that:

(T)his section applies to—

(1) Natural gas produced from any new well not otherwise qualifying for a higher ceiling price; and

(2) Natural gas committed or dedicated to interstate commerce for which a just and reasonable rate was not in effect under the Natural Gas Act; and

(3) Natural gas which was not committed or dedicated to interstate commerce and which was not subject to an existing contract; and

(4) Natural gas produced from the Prudhoe Bay Unit of the North Slope of Alaska and transported through the transportation system approved under the Alaska Natural Gas Transportation Act of 1976; and

(5) Any natural gas which is not covered by any maximum lawful price under any other section of this subtitle. *Id.* at 90.

Many commenters contend that our interpretation of section 109 must proceed from consideration of the language of the statute, and, more specifically, from an attempt to discern the intent of Congress underlying its use of the word "including" in subsection (a).[10] The Commission notes that the common definitions of that word supplied by commenters [11] are accurate and ordinarily serviceable definitions of that word. However, we cannot agree with the commenters who suggest that such a plain meaning of "including", properly applied, supplies any plain meaning to the language of subsection (a).

For example, it has been urged that the Commission define "including" as "something as a constituent, component, or subordinate part of a larger whole". In the context of section 109(a) the category in clause (1) (gas from new wells not subject to a higher maximum lawful price) would be the constituent part, and the introductory clause which precedes the word "including" (natural gas not covered by a maximum lawful price under any other section) would be the "larger whole". In this instance, however, the "component part" of clause (1) undisputably is not part of the larger whole of subsection (a).

The Commission is not prepared to ply the word "including" so that in some contorted form it "plainly" supports either a broad interpretation of section 109(a), or a narrow one. After attempting to discern the plain meaning of the word chosen by the drafters, we cannot reach any conclusion but that the meaning of the word "including" as used in section 109 is ambiguous. We therefore must look beyond the meaning of this one word in determining the scope of applicability of section 109.

Notwithstanding the ambiguity created by the use of the word "including" the Commission believes that the text of section 109, taken as a whole, compels us to follow a narrow interpretation. As noted above, the categories of natural gas described in clauses (2) through (4) of paragraph (a) are comprehended within the introductory language, "natural gas which is not covered under any section of this subtitle". In contrast, the natural gas prescribed in clause (1) falls within that category only to the extent that it is not subject to section 104, 105 or 106, or has not qualified for an incentive price under section 102, 103, 107, or 108. If Congress had intended the result which obtains under the broad interpretation, it could have defined the scope of section 109 by reference only to two categories of gas: natural gas which is not covered by a maximum lawful price under any other section and, natural gas produced from any new well not otherwise qualifying for an incentive price under 102, 103, 107, or 108.

To embrace the broad interpretation would lead us to the anomalous conclusion that Congress drafted four parallel clauses with the intent that one clause would have the substantive effect of expanding the scope of applicability of section 109 set forth in the introductory clause, but that the other three clauses, which do not expand the scope of applicability, would have no substantive effect whatsoever. In contrast, the Commission's interpretation recognizes the introductory clause as a general limitation on the scope of applicability of section 109, and gives equal although limited, effect to the four succeeding clauses, as illustrative of the scope of applicability contained in the introductory clause, to the extent not inconsistent therewith.

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[10] *See supra* notes 5–7 and accompanying text.

[11] *See supra* notes 5 and 6 and accompanying text.

We also believe that the narrow reading of section 109 is the only interpretation that preserves the statutory scheme of Title I and is consistent with other sections of the NGPA. We are persuaded that Congress established the substantive standards under sections 102 and 103 to assure that a producer receive a higher price for gas from new wells when the well is necessary for the development and production of new reserves. Enforcing these substantive standards, the Commission has provided a producer the opportunity to demonstrate that a particular new well is of the type that Congress intended should receive a price higher than the section 104 price, *i.e.*, a new well drilled to produce additional natural gas from newly discovered or developed reserves. A producer of gas from a new, onshore production well is eligible for the section 103 price if it is determined that the well is necessary to effectively and efficiently drain the reservoir. Or, a producer may qualify for a section 102 price if new reserves of gas are produced from a new well which is 2.5 miles from the nearest marker well or, is produced from a previously existing well tapped by a deepening.[12] To make available a price higher than the section 104 price simply because a producer has drilled a new well violates the statutory scheme which contemplates that higher prices will be accompanied by the development of new reserves.

Congress specifically incorporated, in section 104, the just and reasonable price for natural gas already committed or dedicated to interstate commerce in order to provide for the continued production of flowing gas at current prices, adjusted periodically for inflation. To accept the broad interpretation is to suggest that Congress intended to apply the section 104 price to flowing interstate natural gas, and then intended to create a regulatory alchemy, activated by the drilling of a new well, which changes the price applicable to that natural gas from the expressly incorporated just and reasonable rate to the higher section 109 price. We do not believe that Congress intended that result.

Unquestionably, a fundamental purpose of the incentive prices of Title I of NGPA was to encourage investment in the exploration and development of new natural gas reserves. We do not believe however that the Congress intended to affect investment decisions in a manner which would tend to induce capital investment and the use of limited resources for the production of supplies of natural gas which are already available. Yet this result is an inevitable consequence of a broad interpretation of section 109. Under the broad view of section 109, a producer could circumvent a lower price applicable under section 104, 105 or 106, by drilling a new well, even where the well would not qualify as a new onshore production well under section 103 or would not result in the production of new gas under section 102.

Producers may be tempted to use available drilling rigs to drill unnecessary wells, diverting that equipment from efforts to explore and develop new reserves. Resources would be misused, no new gas reserves would be developed, and consumers would enjoy no added benefit for the higher prices they would be required to pay. We believe that Congress could not have intended the economic waste that would result if we adopted the broad interpretation of section 109.

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[12] Implicit in section 102 is the assumption that a new well drilled 2.5 miles from the nearest marker well will produce new reserves. Similarly, section 102 further encourages the production of new reserves by providing an incentive price for gas from a new well, as defined in section 2(3)(B) of the NGPA, which is deepened and completed at a depth of at least 1000 feet below the completion location of each marker well within 2.5 miles of the new well.

The Commission's interpretation of section 109 also draws support from other sections of the NGPA. Section 503(e) provides for the interim collection of the section 109 price for gas from a new well during the period in which the state jurisdictional agency is determining the eligibility of the well for an incentive price. Section 503(e)(1)(B)(i) requires the seller who proposes to make interim collections to provide a sworn statement that the gas is produced from a new well and "that such seller believes in good faith that such natural gas is eligible under this Act to be sold at a price not less than the appropriate maximum lawful price under section 109."

If section 109 were intended to be read broadly, so that a new well would always get at least the section 109(b) price, then it would have been unnecessary for Congress to require the producer to attest that the gas is both from a new well and qualifies for a price no lower than the section 109 price. Unless gas from a new well could be subject to a lower price, the second requirement of the oath statement, that the seller in good faith believe that the gas is eligible for a price no lower than the section 109 price, would be surplusage.

The Commission's interpretation of section 109 is further reinforced by reference to section 503(e)(1)(B)(iii). This provision requires that any interim collections for sales of natural gas from new wells shall be collected subject to a condition of refund in the event it is determined by the appropriate jurisdictional agency that the applicable maximum lawful price is lower than that provided by section 109. However, if section 109 is read to be applicable in all cases to natural gas from a new well, there would be no situation in which the refund obligation in section 503(e)(1) would be triggered, and thus, no reason to have provided for a refund. Only by adopting the narrow interpretation of section 109 can the Commission give full effect to the requirements of section 503(e)(1)(B)(iii) which provide for a refund when gas produced from a new well is found to be subject to a lower maximum price.

In addition we observe that the narrow interpretation is consistent with the economic assumptions on which Congress based the pricing scheme of Title I. Congress had available to it a number of studies on the impact of the provisions of Title I on natural gas prices.[13] These studies assumed the continued applicability over time of sections 104, 105 and 106 to flowing gas. If that gas could be made subject to the section 109 price simply by the drilling of a new well, the continued applicability of section 104, 105 and 106 could not be assumed. Instead, over time, less and less natural gas will be subject to these sections as producers qualify this natural gas for the section 109 maximum lawful price. It would be possible, at some point, that all natural gas which is presently subject to sections 104, 105 and 106 of the NGPA would be subject to the section 109 maximum lawful price; the section 109 price would be the minimum "maximum lawful price" which would be applicable to all natural gas reserves. A reading of section 109 which has the potential to make sections 104, 105 and 106 inapplicable to flowing natural gas is neither reasonable nor consistent with the pricing scheme of the NGPA.

We acknowledge that the support for the Commission's interpretation implicit in the text and underlying policies of the statute is not borne out by the explanation of the scope of section 109 contained in the Joint Statement. As commenters have correctly pointed out, the language of the Joint Statement suggests that Congress intended that section 109 be applicable without limitation to five distinct categories of natural gas, thereby supporting the broad interpretation.[14] As a general rule, the legislative history, including the Conference Report and the accompanying Joint Explanatory Statement, is useful and persuasive evidence of Congressional intent underlying the enactment of a statute. It is, however, no talisman for divining Congressional intent in contradiction to the policies and purpose manifest in the language of the statute and the surrounding legislative scheme. Far greater, if not controlling, weight should be given to those policies and purposes and to the language of sections 109 and 503.[15] In this case, the language of the statute taken as a whole, and the policies underlying the enactment of the NGPA compel us to conclude that Congress intended section 109 to be read narrowly, notwithstanding the suggestion to the contrary that is contained in the legislative history.

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[13] These studies were prepared by the Department of Energy/Energy Information Administration, the staff of the House Subcommittee of Energy and Power, and the Congressional Budget Office. Order No. 23, issued by the Commission on March 13, 1979, in Docket No. RM79-22, refers to the studies (mimeo, pp. 31-32, n. 27).

III. Other Comments

A comment received from Grace Petroleum Corp. suggests that the Commission establish a procedure whereby a producer may obtain an advisory declaration as to the applicability of section 109 to natural gas which they will produce.

Such a procedure has, to some extent, been implemented. The Commission's NGPA Hotline allows producers to obtain informal advisory opinions as to the eligibility of their natural gas for the section 109 price. An official interpretation may be obtained by submitting a written request for such an interpretation to the Commission's General Counsel.[16]

The Natural Gas Pipeline Co. of America (Natural Gas Pipeline) requests the Commission to clarify its interpretation of clause (2) of section 109(a). That clause makes the section 109(b) price applicable to natural gas committed or dedicated to interstate commerce before November 9, 1978, but not subject to a just and reasonable rate under the Natural Gas Act (NGA). Natural Gas Pipeline comments that the Commission has not made clear the types of natural gas which would fall within this category. To avoid uncertainties with regard to filing and pricing requirements, they ask the Commission to identify the circumstance under which an NGA just and reasonable rate would not have been in effect on November 8, 1978, for gas that is committed or dedicated to interstate commerce. They also request that the Commission clarify the status of natural gas sold under protective orders pending the outcome of the Supreme Court's decision in *California v. Southland Royalty Co.* (*Southland*).[17]

Section 109(a)(2) requires the application of two-fold test: first, that the natural gas was committed or dedicated to interstate commerce on November 8, 1978, and second, that that natural gas was not subject to a just and reasonable rate under the Natural Gas Act on November 8, 1978. On November 8, 1978, the Commission had in effect just and reasonable rates for all natural gas subject to the NGA except gas from Alaska and Hawaii. Accordingly, since all natural gas from the lower 48 states was subject to a just and reasonable rate on November 8, 1978, such gas would not qualify under section 109(a)(2) for the section 109(b) price.

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[14] *See* discussion *supra*, note 9, and accompanying text.

[15] The language in the Joint Statement deviates from the text of the statute not only in the area of the scope of applicability of section 109 but in another area. Reference to the Joint Statement also would indicate that section 109 applies to gas which is not the subject of a "first sale". This implication from the Joint Statement, however, is belied by the statutory language. The imprecision in the discussion of section 109 in the Joint Statement is a significant factor which bears on the weight which should be accorded that discussion.

[16] The exact scope and limitations of such interpretations are fully explained in the Commission's order establishing procedures for seeking interpretation or declaratory orders under the NGPA, issued on August 7, 1979, in Docket No. RM79-65, 44 FR 48171 (Aug. 17, 1979).

[17] *California v. Southland Royalty Co.*, 436 U.S. 519 (1978).

Also, gas that was sold pending the outcome of the *Southland* case would not qualify under section 109(a)(2). In that case the Supreme Court considered whether the expiration of a contract to deliver gas to the interstate market terminated the jurisdiction of the Commission to require abandonment authorization. On May 31, 1978, the Court held that the issuance of a certificate of unlimited duration created a Federal obligation to serve the interstate market until abandonment authorization had been obtained; in other words, the service obligation imposed by the Commission survives the expiration of the private agreement that originally gave rise to the Commission's jurisdiction. As a result, gas which was committed or dedicated to interstate commerce remained committed or dedicated, and could not be diverted to the intrastate market until abandonment authorization could be obtained.

Accordingly, if a producer of gas committed or dedicated to interstate commerce did not obtain an abandonment authorization for gas sold pending the outcome of *Southland* prior to November 9, 1978, such gas would have been subject to a just and reasonable rate and therefore outside the scope of section 109(a)(2). Where the application for abandonment authorization was made before November 9, 1978, but no order permitting abandonment was issued until after that date, natural gas sold during the intervening period would still be subject to a just and reasonable rate and therefore excluded from the scope of section 109(a)(2).

IV. Public Procedures and Effective Date

The regulation in Subpart I of Part 271 was originally proposed for comment in November of 1978 and issued as an interim regulation on December 1, 1978.[18] For sixty days thereafter comments were received and during that period public hearings were held on the interim regulations. By this process, the Commission has complied with the provisions of section 502(b) of the NGPA which requires that "[t]o the maximum extent practicable, an opportunity for oral presentation of data, views, and arguments" be afforded for certain regulations under the NGPA.

The regulation adopted by this order rests upon consideration given to the information received during this notice, comment and hearing process. The Commission finds that further notice and public procedure with respect to these rules is unnecessary.

Subpart I of Part 271, in final form, adopts the interim regulation without modification. For this reason, the Commission is dispensing with the publication requirements of 5 U.S.C. 553(d)(1). Accordingly, Subpart I of Part 271, issued as a final regulation, is effective immediately upon issuance of this order.

[Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.;* Department of Energy Organization Act, 42 U.S.C. 7107 *et seq.;* Exec. Order No. 12,009, 42 FR 46267; Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350.]

In consideration of the foregoing, the interim regulations in Subpart I of Part 271, Subchapter H, Chapter I, Title 18, code of Federal Regulations are reissued as final regulations as set forth below, effective immediately.

By the commission.

Kenneth F. Plumb,
Secretary.

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[18] 43 FR 56448 (Dec. 1, 1978).

[¶ 30,136]

45 F. R. 20074 (March 27, 1980)

18 CFR Part 1

[Docket No. RM80-43; Order No. 71]

Rules of Practice and Procedure

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The amendment to § 1.4(d) of the Commission's regulations will permit the Commission to modify, to the extent permitted by law, its existing *ex parte* and separation of functions regulations by rule or order. The Commission will be issuing new *ex parte* and separation of functions rules of general applicability in the near future. In the interim, the Commission recognizes that it may need to modify its existing *ex parte* and separation of functions rules as they apply in certain proceedings.

DATES: Effective March 17, 1980.

FOR FURTHER INFORMATION CONTACT:
June G. Perin, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357-8473.

Issued March 17, 1980.

Before Commissioners: Charles B. Curtis, Chairman; Georgiana Sheldon, Matthew Holden, Jr., and George R. Hall.

The Federal Energy Regulatory Commission is amending § 1.4(d)(2) of its Rules of Practice and Procedure. The amendment will permit the Commission to modify its existing regulations on *ex parte* and separation of function by rule or order, to the extent permitted by law.

The amendment is merely a codification of the extant authority of the Commission to modify its rules at any time as long as the modification does not prejudice any party to a pending proceeding. As such, the amendment to § 1.4(d)(2) is procedural in nature.

The Commission's present *ex parte* and separation of functions rules are more restrictive than the Administrative Procedure Act would require. In addition, the present rules do not apply to oil pipeline proceedings conducted under the authority transferred to the Commission by virtue of the Department of Energy Organization Act. Existing Interstate Commerce Commission *ex parte* and separation of functions rules presently apply to those proceedings.

The Commission is actively considering and will be issuing new *ex parte* and separation of functions rules of general applicability in the near future. In the interim, the Commission recognizes that it may need to modify its existing *ex parte* and separation of functions rules as they apply to certain proceedings at the Commission, including oil pipeline proceedings. For this reason, the Commission finds that good cause exists to adopt the amendment of § 1.4(d)(2) effective immediately.

(Federal Power Act, *as amended,* 16 U.S.C. 792 *et seq.;* Natural Gas Act, *as amended,* 15 U.S.C. 717 *et seq.;* Interstate Commerce Act, *as amended,* 49 U.S.C. 1 *et seq.;* Department of Energy Organization Act, Pub. L. No. 95-91, 91 Stat. 565, *et seq.,* E.O. 12009, 42 FR 46267; Administrative Procedure Act, 5 U.S.C. §§ 500 *et seq.*)

In consideration of the foregoing, Part 1, Chapter I of Title 18 of the Code of Federal Regulations is amended as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,137]

45 F. R. 20785 (March 31, 1980); 45 F. R. 27924 (April 25, 1980)

18 CFR Parts 1 and 3

[Docket No. RM79-32; Order No. 24-B]

Rules of Practice and Procedure; Organization; Operation; Information and Requests

AGENCY: Federal Energy Regulatory Commission.

ACTION: Interim Rule.

SUMMARY: The Federal Energy Regulatory Commission hereby amends its interim regulations regarding applications for adjustments under the Natural Gas Policy Act (NGPA), 15 U.S.C. 3412(c). The definition of "Party" is expanded to include those who have petitioned to intervene but whose petitions have not yet been acted upon, and responses to adjustment applications are required to be filed at the same time petitions to intervene are filed. Further, petitions to intervene are deemed granted unless Staff acted to deny them within 75 days after the date of filing. The separate intervention deadlines for persons served and persons not served are eliminated, and all petitions to intervene must be filed within 15 days after publication in the Federal Register. Applicants for interim relief are required to make appropriate service of their applications. Any party is permitted to file a reply to a request for interim relief within 20 (rather than 10) days after the filing of such a request. The separation of functions provision of this regulation is amended to permit the person who made the decision to grant or deny the adjustment to advise the Commission regarding that adjustment. Staff is also permitted to treat applications for adjustments as requests for interpretations by the General Counsel, where appropriate, such as when the application is based upon a misunderstanding of the law by the applicant. In addition, technical changes are made to this section.

Conforming changes are made to the Commission's rules on interpretations under the NGPA, to accommodate the situation in which an application for an adjustment is treated as a request for an interpretation, *see* 18 CFR 1.42.

Finally, a Commission regulation regarding delegation of authority to the Director of the Office of Opinions and Review, 18 CFR 3.5(i), is amended to streamline the consideration of adjustment applications by permitting the Director to designate the presiding officers in a proceeding to review an initial adjustment decision.

EFFECTIVE DATE: March 24, 1980.

Comments must be received on or before May 25, 1980, by the Secretary, Federal Energy Regulatory Commission, 825 North Capitol St., N.W., Washington, D.C. 20426.

HEARING DATE: June 10, 1980.

ADDRESS: Hearing location: Federal Energy Regulatory Commission, 825 North Capitol St., N.W., Washington, D.C. 20426, at 10:00 A.M., local time.

FOR FURTHER INFORMATION CONTACT: Christine Benagh, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol St., N.W., Washington, 20426 (202) 275-4932.

SUPPLEMENTARY INFORMATION: Before Commissioners: Charles B. Curtis, Chairman; Georgiana Sheldon, Matthew Holden, Jr., and George R. Hall. Procedures for Adjustments of Rules and Orders Issued by the Federal Energy Regulatory Commission Under the NGPA.

Issued: March 24, 1980.

Background

On March 22, 1979, the Commission issued interim procedures [1] under which any person may seek an adjustment from a rule or order issued by the Commission under the Natural Gas Policy Act of 1978 (NGPA).[2] These interim regulations, which are incorporated in § 1.41 of our regulations, implement the provisions of section 502(c) of the NGPA.[3] On November 27, 1979, the Commission amended these regulations to permit Commission waiver, under appropriate circumstances, of the adjustment procedures.[4] In this order we issue further amendments clarifying and modifying the interim adjustment regulations.[5]

Discussion

A. Definitions

Section 1.41(b) defines the term "Party" as used in the adjustment regulations. This order expands that definition to include those who have petitioned to intervene but whose petitions have not yet been acted upon. Party status granted by this revision will terminate if and when the relevant petition to intervene is denied. This change will permit potential intervenors to file timely responses to certain requests for interim relief under § 1.41(m); currently the period for response may elapse before a potential intervenor's petition is acted upon. Amending § 1.41(b)(5) to grant party status to persons who have petitioned to intervene will grant them the right to make timely filings.

B. Intervention

Section 1.41(e) gives a person served with an adjustment application 15 days after service to petition to intervene. That same section grants a person who is not served with the application 15 days from the publication of notice in the **Federal Register** to petition to intervene. After nearly a year of experience with these regulations, we find that there is no particular benefit achieved by imposing two different filing deadlines, and that it will ease administrative recordkeeping if a uniform deadline is established for petitions to intervene. Accordingly, § 1.41(e) is amended to require all petitions to intervene to be filed within 15 days after publication in the Federal Register of the notice of the application for an adjustment.

Section 1.41(e) is further amended to stipulate that any petition to intervene in an adjustment proceeding is deemed granted unless Staff denies it within 75 days after the day of its filing. This procedure will eliminate some of the paperwork involved in the intervention process and further expedite that process.

Section 1.41(f)(1) of the regulations, prior to this Order, prohibited an intervenor from filing a response until the underlying petition to intervene had been granted. This regulation acted to slow the adjustment process, for it forced an interested party to delay any response until notified that the Staff had taken action on the petition to intervene. We believe that it would be beneficial to all parties if each potential intervenor were to file his or her response, if any, to an adjustment application at the same time the petition to intervene is filed. Section 1.41(f) is therefore amended to bring about this result.

C. Interim Relief

Section 1.41(m) specifies the procedures under which an applicant for an adjustment may file a request for interim relief and the standards under which such request shall be considered. This section requires modification and clarification regarding service to intervenors and the time period during which an intervenor must file a reply to a request for interim relief under this subsection.

An applicant seeking interim relief should comply with § 1.41(d)(2), which requires service of the application on any person the applicant reasonably ascertains may suffer direct and measurable economic impact if the relief is granted. If the adjustment proceeding is already under way, any person who has petitioned to intervene in the proceeding is within that class and should also be served, unless the petition to intervene has been denied. Section 1.41(m)(1) is revised to require service on persons who are intervenors or who have pending a petition to intervene.

In most cases a request for interim relief is filed at the same time that the initial application is filed. Thus some potential intervenors (i.e., interested persons other than those served by the applicant under § 1.41(d)(2)) may not become aware of the request until they receive notice in the **Federal Register**.

By then it will almost certainly be too late for them to respond, since replies to interim relief requests must be filed within 10 days of the date the request is filed (*see* § 1.41(m)(3)). To provide these persons with a more reasonable filing period, § 1.41(m)(3) is amended to permit any party[6] to file a reply to such request within 20 days after the filing of a request for interim relief.

D. Separation of Functions

Section 1.41(q), restricts certain Staff members from advising the Commission concerning the appeal from a Staff adjustment order (appeals procedure is governed by § 1.41(j)). Prior to this Order, the Director of the Office of Producer and Pipeline Regulation, or the Director's designee, could not advise the Commission in review of adjustment orders under § 1.41(j)(2). Since the Director's order is an informal proceeding, exclusion of the Director or the Director's designee is unnecessary. Therefore, the separation of functions provision is amended to limit that restriction to witnesses or counsel who participated in the proceeding under § 1.41(j), to review the grant or denial of the adjustment. Further, since this restriction is applicable only to subsection (j) proceedings, paragraph (q) is redesignated by this Order as paragraph (j)(3).

E. Interpretations

The Commission occasionally receives an adjustment application which Staff determines would be more appropriately processed as a request for an interpretation. For example, a person may seek an adjustment from a rule which he or she believes causes a special hardship; however, the applicant's construction of the rule may be incorrect. In reviewing the application, Staff may determine that the perceived hardship would be alleviated, or the position altered, were the applicant to apply the particular regulation correctly.

The most expedient way of dealing with such a situation is to grant Staff the discretion to treat such adjustment application as a request for an interpretation, where appropriate. Accordingly, § 1.41 is amended by adding a new paragraph, (q), entitled "Application for adjustment treated as request for interpretation." (The provision which was designated as paragraph (q) is redesignated by this Order as paragraph (j)(3).) In cases where Staff determines that an interpretation rather than an adjustment is appropriate, the application will be treated under the provisions of § 1.42, and the applicant and all parties will be so notified. The application for adjustment, if deemed a request for an interpretation under new § 1.41(q), would not be acted upon until the interpretation is issued by the Commission's General Counsel under § 1.42. If the applicant believes the interpretation given does not obviate the need for an adjustment, the applicant may reinstate the original adjustment application merely by notifying the Commission.

F. Conforming and Technical Changes

Section 1.41(a)(3)(i)(F) states that § 1.8(a)–(c) and (e)–(f), which set forth procedures for intervention, are applicable in an adjustment proceeding. However, § 1.8(f)(2) requires action on petitions to intervene. This requirement is made no longer applicable to adjustment proceedings by the revision of § 1.41(e) to deem petitions to intervene to be granted unless specifically denied by Staff. Accordingly, § 1.8(f)(2) no longer applies to § 1.41 proceedings. Therefore, § 1.41(a)(3)(i)(F) is amended to delete the reference to § 1.8(f)(2).

A further technical change is made to § 1.41(d)(1)(iv) to correct a typographical error. That subsection pertains to service requirements and, before this Order, cited § 1.7 (a petition rule) rather than § 1.17 (a service rule). Section 1.41(d)(1)(iv) is amended to reflect the correct citation.

The addition of new paragraph (q) to § 1.41, regarding treating applications for adjustments as requests for interpretations, made by this Order necessitates a conforming amendment to § 1.42, "Interpretations and interpretative rules under the NGPA." Section § 1.42 is expanded by adding a new paragraph, (j), to make that section applicable to requests for adjustments deemed to be requests for interpretations under § 1.41(q).

An additional conforming change is required in § 3.5 of our regulations, which authorizes the delegation of Commission authority to certain Staff officials within the Commission. Section 3.5(i)(1), prior to this Order, permitted the Director of the Office of Opinions and Review (OOR) to designate presiding officers only for § 1.40 review of adjustment orders made under sections 503(c) and 504(b) of the Department of Energy Organization Act. Similar delegation authority for review of adjustment orders arising under section 502(c) of the NGPA streamlines the review decisions, and § 3.5 is so amended.

Effective Date and Public Procedures

These amendments to the interim regulations are being issued as interim rules effective immediately with respect to all pending and future applications. The interim regulations, and these amendments, are procedural and relate to practice before the Commission. In addition, there is an immediate need for regulations which assist the Commission in the implementation of section 502(c) of the NGPA. For these reasons, good cause exists to adopt these amendments effective immediately and to do so without prior notice and comment.

Although they are being made effective immediately, the amendments contained in this Order are interim regulations. So that we may consider appropriate comments prior to issuing final rules, the Commission is affording an opportunity for interested persons to submit written comments, data, views or arguments regarding this order. An original and 14 copies of such comments should be filed by May 26, 1980 with the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. Each submission should include the name and address of the person submitting the comments, should refer to Docket No. RM79-32, and should include the reasons for any recommendations. Comments should state the name, title, mailing address, and telephone number of one person to whom communications concerning the amendment may be addressed. Written comments will be placed in the Commission's public file and will be available for public inspection during regular business hours at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C.

Because this order amends a regulation issued under the NGPA, the Commission will provide an opportunity for the oral presentation of data, views and arguments as required by section 502(b) of the NGPA. A public hearing on this order will be held on June 10, 1980, at the offices of the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C., and will begin at 10:00 a.m., local time.

Requests to participate in the hearing should be directed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should be made no later than June 3, 1980. Requests should refer to Docket No. RM79-32 and should state the name of the person who will be making the presentation, a phone number at which that person may be contacted, and the amount of time requested for the presentation.

Persons participating in the public hearing should, if possible, bring 25 copies of their testimony to the hearing. A list of the participants in the hearing will be available in the Commission's Office of Public Information prior to the hearing and will be available at the Commission on the morning of the hearing.

The hearing will not be a judicial or evidentiary-type hearing, and there will be no cross examination of persons presenting statements. The presentations will be made before a panel whose members will be designated by the Chairman of the Commission. Members participating on the panel before whom the presentations are made may ask questions. If time permits, panel members may also ask such relevant questions as are submitted to them by participants. Other procedural rules relating to the hearing will be announced at the time the proceedings commence. A transcript of the hearing will be made and a copy of that transcript will be placed in the public file for this docket and will be made available at the Commission's Office of Public Information.

(Department of Energy Organization Act, 42 U.S.C. §§ 7107–7352; E. O. 12009, 42 FR 46267; Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301–3432)

In consideration of the foregoing, Part 1, Subchapter A, Chapter I of Title 18 of the Code of Federal Regulations is amended as set forth below, as an interim regulation, effective immediately.

By the Commission.

Lois D. Cashell,
Acting Secretary.

— Footnotes —

[1] Order No. 24, "Procedures for Adjustments of Rules and Orders Issued by the Federal Energy Regulatory Commission Under the NGPA," Docket No. RM79-32 (issued Mar. 22, 1979), 44 FR 18,961 (Mar. 30, 1979).

[2] 15 U.S.C. §§ 3301–3432 (Supp. II, 1978).

[3] Section 502(c) of the NGPA states: The Commission or any other Federal officer or agency authorized to issue rules or orders described in subsection (a) (other than an order under section 301, 302, or 503) shall, by rule, provide for the making of such adjustments, consistent with the other purposes of this Act, as may be necessary to prevent special hardship, inequity, or an unfair distribution of burdens. Such rule shall establish procedures which are available to any person for the purpose of seeking an interpretation, modification, or rescission of, exception to, or exemption from, such applicable rules or orders. If any person is aggrieved or adversely affected by the denial of a request for adjustment under the preceding sentence, such person may request a review of such denial by the officer or agency and may obtain judicial review in accordance with section 506 when such denial becomes final. The officer or agency shall, by rule, establish procedures, including an opportunity for oral presentation of data, views, and arguments, for considering requests for adjustment under this subsection. 15 U.S.C. § 3412 (Supp. II, 1978).

[4] Order No. 24-A, "Procedures for Adjustments of Rules and Orders Issued by the Federal Energy Regulatory Commission Under the NGPA," Docket No. RM79-32 (issued Nov. 27, 1979), 44 FR 69,284 (Dec. 3, 1979).

[5] The Commission is currently undertaking a detailed review of all portions of §§ 1.40 and 1.41. At the time that final regulations are promulgated for those sections, all comments from the public concerning the adjustment procedures will be discussed.

[6] By filing a petition to intervene at the same time as the response, an interested person becomes a "party," at least until such time as the underlying petition to intervene is denied. *See* discussion at Section A, *supra.*

[¶ 30,138]

45 F. R. 21623 (April 2, 1980);
45 F. R. 33600 (May 20, 1980)

18 CFR Parts 3, 141, and 260

[Docket No. RM80-17; Order No. 74]

Order Revising Monthly Statements

Issued March 28, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission hereby revises Form No. 5, Monthly Statement of Electric Operating Revenue and Income (18 CFR 141.25) and Form No. 11, Natural Gas Pipeline Company Monthly Statement (18 CFR 260.3). The revisions delete certain information requirements because they are no longer needed by the Commission. The changes in these forms reflect the results of an ongoing form validation program of the Commission, the purpose of which is to reduce reporting burdens placed on companies that are subject to the jurisdiction of the Commission.

EFFECTIVE DATE: March 28, 1980.

FOR FURTHER INFORMATION CONTACT: James Kitchen, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Room 3408 North Building, Washington, D.C. 20426, (202) 357-9212.

I. Background

On December 21, 1979, the Federal Energy Regulatory Commission (Commission) issued a Notice of

Proposed Rulemaking (45 FR 48 January 2, 1980). This rulemaking proposed to revise Form No. 5, Monthly Statement of Electric Operating Revenue and Income, and Form No. 11, Natural Gas Pipeline Company Monthly Statement, to reflect the results of the Commission's ongoing validation program,[1] the purpose of which is to reduce the reporting burden on the industries regulated by the Commission.

II. Summary of Comments

In response to the proposed rulemaking, the Commission received comments from 49 respondents. These included three industry associations, 31 electric utilities (representing 45 jurisdictional operating companies), 14 jurisdictional natural gas companies, and one individual. The general reaction to the proposed rulemaking was very favorable. Some changes were suggested and a few requests for clarification were made.

Among the changes proposed by the Commission to Form No. 5, was the elimination of the requirement to report previous year data, since this information can be obtained from prior filings. Items related primarily to income and expenses were also proposed for deletion because the Commission no longer needed this information.

The Commission also proposed to raise the revenue limit used to a $2.5 million [2] to a $100 million minimum. The Commission felt that a valid statistical frame for regulatory purposes could still be obtained at the $100 million level.[3]

A section was proposed to be added to page 2 of Form No. 5 for footnotes by responding companies and the form title would be changed to "Electric Utility Company Monthly Statement."

The Commission also proposed to eliminate certain data items from Form No. 11 which the Commission no longer needs. A separate page for footnotes by responding companies would also be added.

Finally, the Commission proposed to shorten the reporting period for both forms from 40 days to 20 days. According to the published statistics from them, the shortened period would be desirable in light of reduced reporting burdens and would permit the Administration to publish more current statistical data.

In addition to the statement of proposed revisions in the Notice, the Commission posed three specific questions to the public. These asked whether the revisions affected any Commission or State regulatory function, whether there was any reason known for continued collection of data proposed for elimination, and whether the proposed twenty-day filing deadline was practical.

Nine of the electric and eight of the natural gas respondents commented that they did not believe the revisions of required data would affect any Commission or State regulatory functions. Eight of the electric and eight of the natural gas respondents replied they did not know of any other Federal agency that needed the data proposed for elimination.

Forty-nine of the respondents stated that the proposed twenty day filing period is impractical and unrealistic. Alternatives using 25, 30, 35, or 40-day period were suggested. The respondents indicated that the reduction in data did not correspondingly reduce the time needed to prepare and make a filing.

Some of the specific complaints against the 20-day filing deadline were as follows:

(1) Jurisdictional companies frequently would be unable to close their books before the end of the twenty day period. The companies would, therefore, be unable to provide the requested information on a timely basis. Although the Commission suggested that respondents file "estimates subject to later revision" in order to meet the 20-day deadline, commenters noted that the practice would only create extra paperwork and increase the possibility for error in reporting.

(2) In several instances, financial information required by the Commission would have to be approved by a Board of Directors before it is released to the

public. If the 20-day deadline occurred before the date of a Board meeting, a reporting company would be faced with an unreasonable disclosure conflict.

(3) Parties using computers to collect the required information from large geographic areas would be unable to receive and tabulate the data in time for the deadline.

(4) Some companies would have to increase their work force or impose overtime hours on a regular basis in order to make a timely filing. The extra costs involved would eventually be passed to the consumer.

(5) One commenter noted that the present 40-day reporting period was established because of the difficulty in meeting a 30-day period earlier in effect.

We agree with respondents that the 20-day reporting period originally proposed by the Commission would place an unreasonable burden on the respondent companies. Further, the accuracy of information, which is essential to our regulatory needs, would suffer to an undesirable extent. With this in mind, we intend to retain the 40-day reporting period.

A few respondents raised two questions in connection with four data items proposed to be gathered on our forms for the Department of Commerce. They wished to know first, how the Department of Commerce uses the data, and second, whether the data should reflect "total company" operations instead of only that information related to operations subject to the Commission's jurisdiction.

With respect to the first question, the Bureau of Economic Analysis (BEA) and the Bureau of Census (BC) of the Department of Commerce have used selected data from Forms No. 5 and 11 for some time.

BEA uses data from lines 13, 14, and 15 of Form No. 5 and from lines 20, 25 and 27 of Form No. 11 in conjunction with similar data from other industries to derive the estimates of the corporate profits component of the gross national product. Similar data are also collected by other government agencies from regulated industries to determine gross profits (before income taxes) and to estimate allowances for funds during construction. This information was previously determined after sifting through the massive amounts of data collected from the old Forms No. 5 and 11.

Since 1974, BC has been using data from line 16 of Form No. 5 and from line 32 of Form No. 11 as components to derive monthly and annual estimates of the value of construction put in place in the United States.[4]

With respect to the second question, and pursuant to requests for clarification, both Forms have been revised to reflect "total company operations" for the four line items of data being gathered for the Department of Commerce. The information which is collected from companies which the Commission does not utilize for jurisdictional purposes is nevertheless used by BEA in compiling its statistical reports.

A number of comments were filed concerning clarification and format of the statements and instructions. For example, the suggestions to eliminate a "Date Prepared" block, and to round figures to the nearest thousand in accord with other tables, were accommodated.

A few recommendations were not adopted, however, such as a request to define "significant" in the requirement to disclose "any adjustments significantly affecting this monthly statement." The Commission determined that the term involves a value judgment and is not subject to definition.

One commenter suggested that the line items pertaining to the monthly and cumulative amounts collected which are subject to refund (proposed table 3, lines 6 and 8) duplicated the reporting requirements of 18 CFR 154.67(c). *Reports.*[5]

Section 154.67(c) requires annual reporting for each rate proceeding in a specific docket, categorized by purchaser and billing period. Form No. 11, on the other hand, requires reporting in aggregate amounts, not in the detail prescribed in § 154.67(c), of all rates or charges collected which are subject to refund. The aggregated reporting in

Form No. 11 has been, and will continue to be, a data requirement of the Commission.

III. Public Procedures and Effective Date

The Commission has complied with 5 U.S.C. § 553 by having provided public notice and an opportunity to participate in this rulemaking. Immediate adoption of the revisions to Forms No. 5 and 11 will promote an expeditious reduction of unnecessary reporting burdens. Therefore, under 5 U.S.C. § 553(d) the Commission is making these changes effective immediately for reports to be filed for the month beginning March 1, 1980.

(Natural Gas Act, as amended, 15 U.S.C. §§ 717–717w; Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301–3432; Federal Power Act, as amended, 16 U.S.C. §§ 792–828c; Department of Energy Organization Act, 42 U.S.C. §§ 7101–7352; E.O. 12009, 3 C.F.R. 142(1978).)

For the foregoing reasons, FPC Form No. 5, Monthly Statement of Electric Operating Revenue and Income prescribed by § 141.25, Chapter I, Title 18 of the Code of Federal Regulations, and FPC Form No. 11, Natural Gas Pipeline Company Monthly Statement, prescribed by § 260.3, Chapter I, Title 18 of the Code of Federal Regulations are revised by the Commission as set forth in Attachments A and B, hereto.

In addition to the foregoing, Parts 3,141 and 260 of Chapter I, Title 18 of the Code of Federal Regulations are amended by the Commission as set forth below.

By the Commission.

Lois D. Cashell,
Acting Secretary.

— Footnotes —

[1] See also Order No. 53, Docket No. RM79-38, issued October 23, 1979.

[2] "[A]ll class A electric utilities, both privately and publicly owned." 18 CFR 141.25; *see* 18 CFR 101.

[3] Certain other utilities specifically designated in Form No. 5 would also be required to file, so representative data concerning energy sales could be collected from all states.

[4] Details regarding use of this data may be found in Department of Commerce, Bureau of Census Construction Reports—Series C 30-745, "Value of Construction Put in Place: 1947–1974."

[5] Commission Order No. 47, issued September 10, 1979 (Docket No. 77-22).

[¶ 30,139]

45 F. R. 22891 (April 4, 1980)

18 CFR Part 282

[Docket No. RM80-46]

Incremental Pricing; Rule Adopting Revised Alternative Fuel Price Ceilings for the Month of April 1980

Issued March 28, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Interim rule.

SUMMARY: The Federal Energy Regulatory Commission hereby issues an interim rule to establish revised alternative fuel price ceilings for the month of April 1980 under the incremental pricing program. The revised ceilings supersede those ceilings published by the Energy Information Administration of the Department of Energy on March 20, 1980.

DATES: Effective March 28, 1980. Comments due April 30, 1980. Date of public hearing to be announced later.

ADDRESS: All comments to: Office of the Secretary, Federal Energy Regulatory Commission, 825 No. Capitol Street, N.E., Washington, D.C. 20426. Hearing location to be announced. (Reference Docket No. RM80-46.)

FOR FURTHER INFORMATION CONTACT: Alice Fernandez, Office of Pipeline and Producer Regulation, 825 No. Capitol St., N.E., Washington, D.C. 20426, (202) 357-8965.

Issued March 28, 1980.

I. Discussion

The Commission's incremental pricing regulations under the Natural Gas Policy

Act of 1978 (NGPA) affect the price that industrial users subject to the regulations must pay for natural gas. Pursuant to section 204(e) of the NGPA, the Commission's rules (at §§ 282.402 through 282.405) place ceilings on price levels to incrementally priced users based on the cost of alternative fuel oils in each state or region. Under the Commission's regulations, ceiling prices each month are currently established on the basis of the price of high sulfur No. 6 fuel oil in the 48 contiguous states. These prices are published "on or before the twentieth day" of the preceding month. Because of the functions vested in the Energy Information Administration (EIA) of the Department of Energy, the responsibility for collecting and compiling this fuel price data, as well as the publication thereof, has been carried out by EIA.

On March 18, 1980, alternative fuel ceilings for April were issued by EIA (45 FR 18109, March 20, 1980). The Commission has reviewed the published alternative fuel prices which were to be effective for April 1980. We observe that in a number of instances the published prices represent a significant increase over the March prices. The Commission has received notice from pipelines, distributors, end users, and EIA itself that current actual prices are lower than the published ceilings in some states. The Commission is therefore concerned that significant industrial fuel switching may occur.

The Commission has determined that the disparity in some states or regions between the alternative fuel prices published by EIA and the observed prices is aggravated by the application of a computational method employed by EIA that was designed to minimize month-to-month variations in published alternative fuel prices.

The Commission has determined that, under present market conditions, the employment of the computational method used for computing April ceilings may prove inconsistent with the statutory directive to reduce consumer price impacts resulting from, or likely to result from, significant loss of industrial load. We have, therefore, asked EIA to recalculate the alternative fuel prices that will be in effect for April 1980 using a method which is more responsive to changes in current prices. The recalculated prices are, in many cases, significantly lower than the previously published April prices. Moreover, the Commission takes official notice that the market price for high sulfur residual fuel oil appears to be continuing its recent downward trend. For this reason, and in order to guard against inadvertent industrial load loss occurring during this market transitional period, the Commission has determined to publish and make effective alternative fuel prices for the month of April 1980 which shall be the *lower* of (1) the alternative fuel price on March 20, 1980, or (2) the recalculated current prices supplied by EIA.

II. Amendment Adopted

The Commission's action in this matter is adopted as an amendment to its regulations. Specifically, the Commission hereby amends the regulation which provides that the alternative fuel price ceilings which shall be effective for any one month shall be those published on or before the twentieth day of the preceding month, § 282.404(a), to add a provision providing that the alternative fuel price ceilings for the month of April 1980 shall be those set forth in the regulations rather than those published on or before March 20. The effect of this provision is to supersede the provision that the ceilings for the month of April 1980 would be those published on or before March 20, 1980.

III. Effective Date

This regulation is being issued effective immediately on an interim basis, because the Commission finds that the need to revise the ceilings published on March 20 constitutes good cause to waive the thirty day publication requirement contained by section 553(d) of the Administrative Procedure Act.

IV. Comment Procedures

A. *Written Comments.* Interested persons are invited to submit written comments, data, views, or arguments with respect to this interim rule. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should reference Docket No. RM80– An original and 14 copies should be filed. All comments received prior to 4:30 p.m. EDT, April 30, 1980, will be considered by the Commission prior to promulgation of a final regulation. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection in the Commission's Office of Congressional and Public Affairs, Division of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours.

B. *Public Hearing*. A public hearing on this interim rule will be held on a date and at a location to be announced at a later date.

(Natural Gas Policy Act of 1978, Pub. L. No. 95–621, 92 Stat. 3350, 15 U.S.C. 3301, *et seq.*)

In consideration of the foregoing, the Commission amends Part 282 of Subchapter I, Chapter 1, Title 18, Code of Federal Regulations, as set forth below, effective immediately.

By the Commission.

Lois D. Cashell,
Acting Secretary.

[¶ 30,140]

45 F. R. 23413 (April 7, 1980)

18 CFR Part 46

[Docket No. RM80–9]

Public Utility Filing Requirement and Requirements for Persons Holding Interlocking Positions; Order Issuing Final Regulations

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: This rule implements, in part, section 211 of the Public Utility Regulatory Policies Act of 1978 which created new section 305(c) of the Federal Power Act. Congress authorized the Federal Energy Regulatory Commission to prescribe, in form and manner, a written statement to be filed by any person holding interlocking positions in both a public utility and in any of certain other specified entities. Persons subject to this rule will be required to file such written statement concerning such positions annually. The written statement is due by April 30, 1980.

EFFECTIVE DATE: April 2, 1980.

FOR FURTHER INFORMATION CONTACT: Colette K. Bohatch, Federal Energy Regulatory Commission, Office of the General Counsel, Room 3335, 825 North Capitol Street, NE., Washington, D.C. 20426 (202) 357–8608.

April 2, 1980.

I. Introduction

This rule implements, in part, section 211 of the Public Utility Regulatory Policies Act of 1978 (PURPA) which amended section 305 of the Federal Power Act (the Act) by adding a new subsection (c). Section 305(c) states two separate requiremtns. One directs any person holding certain executive positions [1] in both a public utility and any one of certain other entities [2] to file with the Commission a written statement regarding such positions. The second requirement directs public utilities to name their twenty largest purchasers who are entities covered by this rule.

The first statutory requirement is set forth in section 305(c)(1) which states that:

> On or before April 30 of each year, any person, (holding certain executive positions with a public utility and any one of a number of other entities identified in section 305(c)(2)) * * * shall file with the Commission, in such form and manner as the Commission shall by rule prescribe, a written statement concerning such positions held by such person.

This second statutory requirement is set forth in section 305(c)(2)(F) which states that:

> On or before January 31 of each calendar year, each public utility shall publish a list,

> pursuant to rules prescribed by the Commission, of (its twenty largest purchasers of electric energy within the meaning of section 305(c)(2)(D)) * * * for purposes of any filing under * * * (section 305(c)(1)).

Proposed regulations concerning both of these statutory requirements were issued by the Commission on November 14, 1979.[3] A five week comment period ended on December 21, 1979. For the purpose of providing the public utilities sufficient time to publish the purchaser lists by January 31, 1980, the Commission decided to implement that statutory requirement as soon as possible, leaving implementation of the requirement concerning the filing of the written statement regarding interlocking positions to a later order.

Accordingly, the Commission issued a final rule on January 11, 1980 in Order No. 67 implementing section 305(c)(2)(F) by directing public utilities to file with the Commission, by January 31, 1980, lists of their largest purchasers.[4] The balance of the regulations relating to the filing requirement for persons holding certain executive positions are being finalized herein.

II. Background

Interlocking positions involving public utilities have been subject to regulation by the Federal Energy Regulatory Commission (Commission) and its predecessor pursuant to section 305 of the Act. Section 305(b) [5] requires that any person desiring to hold the positions of officer and director with a public utility and any one of other specified entities must receive prior authorization from the Commission. Section 305(b) covers interlocking positions between public utilities, and between a public utility and any of the following:

> Any bank, trust company, banking association, or firm that is authorized by law to underwrite or participate in the marketing of securities of a public utility, or * * * any company supplying electrical equipment to such public utility.

Section 305(c) [6] imposes a filing requirement upon persons who hold certain executive positions with public utilities and with other entities, including persons who may have been authorized under section 305(b) to hold interlocking positions. Under section 305(c), such person must also file an annual written statement concerning those positions. The entities other than public utilities covered by section 305(c) are the following:

(1) Any bank, trust company, banking association, or firm that is authorized by law to underwrite or participate in the marketing of securities of a public utility *(parallel provision in section 305(b));*

(2) Any investment bank, bank holding company, foreign bank or subsidary thereof doing business in the United States, insurance comapny, or any other organization primarily engaged in the business of providing financial services or credit, a mutual savings bank, or a savings and loan association;

(3) Any company, firm, or organization which produces or supplies electric equipment or coal, natural gas, oil, nuclear fuel, or other fuel, for the use of any public utility *(parallel provision in section 305(b) as to any company supplying electrical equipment to the interlocked utility);*

(4) Any entity specified as one of a utility's twenty largest retail purchasers pursuant to Order No. 67; and

(5) Any company, firm, or organization which is controlled by any company, firm, or organization listed above.

III. Summary of Comments and Final Rule

A. Comparison with Regulations in Part 45

Forty-three written comments were received by the Commission in this docket. Many of the commenters requested that the Commission reconcile certain differences between the proposed rule concerning reporting of interlooking positions and the existing regulations in Part 45.

One difference between the proposed regulations for Part 46 and those in Part 45 is the definition of "electrical equipment." Part 45 does not define "electrical equipment." Edison Electric Institute (EEI) treated this issue at length and concluded that any definition adopted in Part 46 will alter the scope of the term "electrical equipment" which has been developed through case law construing Part 45.

The Commission has chosen to define "electrical equipment" in Part 46 in order to provide necessary guidance but intends to institute a rulemaking to amend Part 45 to add an appropriate definition for "electrical equipment" for that part. The Commission will at that time request the public to comment on whether such conformity would be in the public interest.

A second difference between Part 45 and Part 46 stems from a difference between sections 305(b) and 305(c) regarding the scope of the term "public utility." Section 305(b) does not explicitly define "public utility," but the applicable definition appearing in section 201(e) of the Act states, in pertinent part:

> The term "public utility" when used in this Part (Part II) or in the Part next following means any persons who owns or operates facilities subject to the jurisdiction of the Commission under this Part * * *

Section 305(c), in contrast, explicitly states that, for purposes of that section, "public utility" includes "any company which is part of a holding company system which includes a registered holding company unless no company in such system is an electric utility" but does not otherwise define that term.

A comprehensive definition for "public utility" in Part 46 is crucial for determining which entities are covered and who may have to file a written statement. The final regulations, therefore, define "public utility" in § 46.2(a)[7] as follows:

> "Public utility" has the same meaning as in section 201(e) of the Federal Power Act and further includes any company which is part of a holding company system which includes a registered holding company unless no company in such system is an electric utility within the meaning of section 3 of the Federal Power Act. Such term does not include any rural electric cooperative which is regulated by the Rural Electrification Administration of the Department of Agriculture or any other entities covered in section 201(f) of the Federal Power Act.

Certain organizations are excluded from this definition because they have been excluded from the Commission's jurisdiction by statute. Such organizations include political subdivisions of a State, e.g., irrigation districts, drainage districts, and municipalities. Certain electric cooperatives approved by the Rural Electrification Administration (REA) have also been excluded by Commission decision.[8] The REA, which finances these cooperatives, also exercises extensive regulatory authority over their development and operation. In the past the Commission has not exercised jurisdiction over such REA approved cooperatives. We see no reason to change such policy here. In order to make this clear, the Commission has also amended two definitions to explicitly exclude such REA cooperatives, namely, "purchaser" in § 46.2(c), and "entity" in § 46.2(e).

A final difference between Parts 45 and 46 involves the categories of covered executive positions. The executive positions subject to Part 45 are defined for all covered entities as follows:

> The positions subject to this part shall include those of any person elected or appointed to perform the duties or functions ordinarily performed by a president, vice president, secretary, treasurer, general manager, comptroller, chief purchasing agent, director or *partner*, or to perform any other similar executive duties or functions, in any corporation within the purview of section 305(b) of the act (emphasis added).

Part 46 uses similar language, excluding the term "partner," to define the executive positions applicable to public utilities but adds the terms "partner, appointee, or representative" to define the positions applicable to all other covered entities. The addition of these terms is supported by the statute. Section 305(c) explicitly uses "partner, appointee, or representative" in describing positions applicable to only certain covered entities while section 305(b) does not use these terms.

Therefore, the Commission does not believe conformity of Part 46 to Part 45 in this regard is warranted.

B. General Rule—Definitions

Nature and Degree of Control. In the Notice of Proposed Rulemaking, the Commission requested that the public recommend a quantitative definition for "control" which, as proposed, was defined only by qualitative standards. Most commenters suggested language from various other Federal statutes which define "control."

Sullivan & Cromwell, Duke Power Company, Troutman, Sanders, Lockerman & Ashmore, and Central Illinois Light Company referred specifically to the following statutes:

(1) The Investment Company Act of 1940, under which ownership of 25 percent of the voting securities of a company creates a presumption of control;[9]

(2) The Bank Holding Company Act of 1956, under which ownership, control, or power to vote 25 percent of voting securities raises a rebuttable presumption of control, while ownership of 5 percent raises a rebuttable presumption of noncontrol;[10] and

(3) The Public Utility Holding Company Act of 1935, which establishes a presumption of control with ownership of 10 percent of voting stock.[11]

Ohio Edison Company also referred to the 25 percent ownership test of the Investment Company Holding Act of 1940. Dayton Power & Light Company stated, without reference to any statute, that a 10 percent ownership test is indicative of true control. In sharp contrast, Public Service Electric & Gas Company, Newark, New Jersey (Public Service—New Jersey) suggested an 80 percent ownership test based on the provisions in the Internal Revenue Code for tax-free organizations.[12]

Using percentage of ownership or power to vote securities as the measure of control makes it difficult to set a limit applicable to large corporations as well as small. A control test which not only uses a percentage limit but also a rebuttable presumption provides some degree of certainty for the definition of "control" while incorporating flexibility to meet diverse corporate ownership circumstances.

The Commission has concluded, therefore, that the following test is appropriate for the purposes of section 305(c): Ownership or power to vote, directly or indirectly, 10 percent or more of the voting securities of any entity raises a rebuttable presumption of control. If a company, however, owns or has power to vote less than 10 percent of the voting securities of another company, there is no presumption of non-control. The Commission recognizes that control can exist when ownership of voting securities is less than 10 percent but under this circumstance there must be a demonstration that control does exist.

Parent and Subsidiary Question. Gulf Power Company, Ohio Edison Company, Consolidated Edison Company of New York, Sullivan & Cromwell, Troutman, Sanders, Lockerman & Ashmore, and Central Illinois Light Company recommended deleting the phrase "any parent and subsidiary of any corporation" from the definition of "business entity." They argued that, as proposed, this definition exceeds the scope of section 305(c)(2)(F) which defines as a covered entity "any company, firm or organization which is *controlled by* any company, firm or organization (identified in section 305(c)(2))" (emphasis added). They contended that the phrase "controlled by" does not cover a parent of any company, firm, or organization identified in section 305(c)(2).

Regarding subsidiaries, they further stated that the concept of "controlled by" is already included in § 46.4(f) (Covered entities) of the proposed rule and therefore, as to "subsidiary," the definition of "business entity" [13] is redundant.

The Commission has reviewed the statute in light of these comments and, pursuant to its authority under section 305(c), has concluded that parents of entities described in section 305(c) are not covered but that subsidiaries are.

Therefore, the Commission has modified the final rule to exclude parents of these entities from coverage of these regulations. The Commission, however, believes that it has adequate authority under other provisions of the law to ask for the filing of a written statement from parent companies and makes no judgment at this time as to whether or not it should exercise its authority.

Entity. Niagara-Mohawk Power Corporation (Niagara-Mohawk) suggested expanding the exemption for municipalities in the definition of "entity" to include Federal, State and local governmental agencies. Niagara-Mohawk argued that many public agencies authorized by Federal or State law rely for leadership upon community leaders who are appointed to such positions and who serve with little or no compensation from these public agencies. Because these people serve in such positions as a public service to their communities, Niagara-Mohawk contended that there is little likelihood of their exercising harmful influence in such positions and that, in any event, there are other, more appropriate checks on the local level for any possible problems.

The Commission has adopted this suggestion because it believes that the statutory purpose of monitoring certain interlocking positions will not be frustrated by excluding these governmental agencies from the definition of "entity."

Electrical Equipment. The definition of "electrical equipment" was the subject of many comments which collectively suggested that the definition was overly broad and should either be narrowed or deleted altogether. They stated that this definition encompasses equipment which has a variety of industrial and non-industrial uses which do not always serve an electrical purpose and concluded that the definition unjustifiably expands the Commission's jurisdiction by broadening the filing requirements to include companies which do not supply electrical equipment.

Various suggestions were offered for modifying the proposed definition. Southern California Edison Company (Southern California), Potomac Electric Power Company, and Carolina Power & Light Company suggested eliminating the term "component" from the definition. Duke Power Company and Southern California commented further that a supplier of small components may not know how the components are used by its utility customers to determine if the components are "electrical equipment."

Sullivan & Cromwell, Detroit Edison, Southern California, and Central Illinois Light Company recommended adding language to emphasize design, purpose, or function of the equipment. Public Service-New Jersey suggested that "electrical equipment" should be limited to equipment manufactured solely for the use of an electric utility (Consolidated Edison Company of New York suggested the terms "primary" and "directly"; the law firm of Leva, Hawes, Symington, Martin & Oppenhiemer suggested the use of the terms "primary" and "customary"). Alabama Power suggested covering only major electrical equipment traditionally used by utilities and designed for a specific utility customer.

Public Service-New jersey, Cambridge Electric Light Company, and EEI suggested substituting pertinent categories from the Standard Industrial Classification System developed by the Department of Commerce [14] instead of the categories from the Commission's Uniform System of Accounts which are included as a footnote to the definition.

Further commenting on the breadth of the definition, Public Service-New Jersey and DeBevoise & Liberman argued that the definition was not consistent with portions of the legislative history for section 305(b) and pertinent case law. Reid & Priest and Steel, Hector & Davis discussed narrowing the scope of the definition of "electrical equipment" in view of the statutory purpose of section 305(b) to eliminate the evils of interlocking business relationships.

Lastly, a *de minimis* test was proposed by Steel, Hector & Davis, San

Diego Gas & Electric Company, Central Illinois Light Company, and EEI that required a minimum of electrical equipment transactions be completed between the utility and a supplier before such supplier would be covered by the rule.

In view of these suggestions, the Commission has decided to narrow the scope of the definition of "electrical equipment." The revised definition set forth in § 46.2(f) states:

> "Electrical equipment" means any apparatus, device, integral component, or integral part used in an activity which is electrically, electronically, mechanically, or by legal prescription necessary to the process of generation, transmission, or distribution of electric energy.

This revised definition also includes, as a guide only, a footnote reference to various accounts in the Commission's Uniform System of Accounts even though certain items can be found in the accounts which are clearly not "electrical equipment" within this definition. For example, a master clock, although electrically operated, is not used in an activity which is "necessary to the process of generation, transmission, or distribution of electric energy." [15] For this reason, the accounts merely serve as a guide.

The Commission believes that the revised definition of "electrical equipment" also eliminates the small component problem raised by Duke Power Company because equipment covered by the rule must be *necessary* to the process of generating, transmitting, or distributing electric energy. "Nuts and bolts" purchased off the shelf are not intended to be covered by the revised definition of "electrical equipment."

To further deal with the concerns regarding the scope of the rule expressed by the commenters, the Commission has defined the term "produces or supplies" in section 305(c)(2)(C) which covers "any company, firm or organization which produces or supplies electrical equipment or coal, natural gas, oil, nuclear fuel, or other fuel, for the use of any public utility." The new definition set forth in § 46.2(g) states that:

> "Produces or supplies" means any transaction including a sale, lease, sale-leaseback, consignment, or any other transaction in which an entity provides electrical equipment, coal, natural gas, oil, nuclear fuel, or other fuel to any public utility either directly or through an entity controlled by such entity. [16]

For example, such a transaction not made *directly* between the utility and the supplier or an entity which controls the supplier is not covered by "produces or supplies." Consequently, an entity engaging in such a transaction would not be a covered entity under § 46.5(c) which incorporates the above-quoted language of section 305(c)(2)(C). Of course, under § 46.5(f), if an entity produced electrical equipment, coal, natural gas, oil, nuclear fuel, or other fuel but supplied it through its parent, any interlock between the subsidiary and a public utility supplied by such subsidiary would have to be reported because the parent would be a qualifying entity under § 46.5(c).

With regard to the *de minimis* test, the Commission considered the adoption of such a test. The Commission recognizes, however, that application of a *de minimis* test would be inconsistent with our recent order in *Charles T. Fisher, III*, Docket No. ID-1758 issued October 25, 1979.

In that case, Mr. Fisher applied for an approval to hold interlocking positions with a public utility and with a supplier of electrical equipment pursuant to section 305(b) of the Act. Mr. Fisher argued that because the supplier's sales to the interlocked utility were small, the supplier should not be found to qualify as a supplier of electrical equipment within the meaning of section 305(b). Noting that this section refers merely to sales of electrical equipment without specifying any quantity threshold, the Commission rejected the argument that a *de minimis* test could be applied to determine whether it had the jurisdictional obligation to authorize or reject this kind of interlocking position.

However, the Commission did consider the volume of sales in determining whether, on the merits, his application should be approved.

Similarly, we find that section 305(c)(2)(C) contains no minimum quantity threshold for electrical equipment supply. Moreover, section 305(c), unlike section 305(b), bases jurisdiction on the *production or supply* of electrical equipment for the use of any public utility, not simply on sales to the interlocked public utility. Here as in *Fisher*, we require compliance with the statutory requirements and make no exclusion based on the amount of sales.

The suggestion that the Standard Industrial Classification System be substituted for the Uniform System of Accounts must be rejected. There is no compelling reason advanced by the commenters for this substitution, particularly when the latter system was developed by the Commission for use in its daily work. Since the footnote reference to the Commission's accounts system serves as only a guide, there is even less reason to make the suggested substitution.

Appointee and Representative. In the proposed rule, the Commission did not define the statutory terms "appointee" and "representative" but solicited comments on their scope with the intention of incorporating pertinent definitions in the final rule. Many commenters [17] suggested that these terms be limited to cover only persons having the ability to contractually bind or to serve a management function for the subject entity. Many of the commenters recommended excluding attorneys, accountants, and consultants from the scope of the rule. Based upon the issues raised in these comments, the Commission has added the following definitions to the rule in § 46.2 (h) and (i), respectively:

> "Appointee" means any person appointed on a temporary or permanent basis to perform any duties or functions as described in § 46.4(a).
>
> "Representative" means any person empowered, through oral or written agreement, to transact business on behalf of an entity and any person who serves as advisor regarding policy or management decisions of the entity. The term does not include attorneys, accountants, architects, or any other persons who render a professional service on a fee basis.

An exclusion has been provided in the definition of "representative" for attorneys, accountants, architects, and other persons who render a professional service on a fee basis. Many commenters suggested that the Commission incorporate an exclusion for such persons who render advice to clients but who do so without having power over policy or management decisions of their clients. Consultants who render their service on a fee basis would also be excluded.

The Commission believes that consultants, particularly if they are former officers or directors of a company, may well be in a position which permits them to continue to influence the decisions of that company. Consultants, from time to time, may direct the policy or managment of a company without being visible policy makers. If they do so and are not paid on a fee basis they would be covered by this rule.

C. General Rule

The word "executive" has been inserted in § 46.4(a) (General rule) preceding the phrase "duties or functions" in accordance with a suggestion by Gulf Power Company. This addition emphasizes the types of functions and the levels of management deserving scrutiny under this rule. When a person is responsible for such executive duties or functions in a public utility and any covered entity, the opportunities to transmit significant information from one company to the other and thus to influence the decisions of another company are increased.

D. Filing Requirements—Compensation

As proposed, the regulations would have required that a person holding interlocking positions must report the compensation received from the public utility and from the other interlocked entity, if the compensation from either is greater than $10,000. The Commission requested comments regarding the $10,000 limit.

Rochester Gas & Electric Corporation, Baltimore Gas & Electric Company, Central Illinois Light Company, Potomac Electric Power Company, and Florida Power & Light Company questioned, as a threshold matter, whether the Commission has authority to inquire as to compensation that a person filing under the rule receives from any section 305(c) entity or should inquire of such a confidential matter when not explicitly mandated to do so.

Hy-Vee Food Stores, San Diego Gas & Electric Company, Iowa Southern Utilities Company (EEI concurred in Iowa's comment), Florida Power & Light Company, and Baltimore Gas & Electric Company argued against disclosure of compensation on other grounds; they contended that the Commission should not require such disclosure for any entity which is beyond the traditional regulatory jurisdiction of the Commission. They also alleged that it would be harsh for persons holding executive positions with an entity which is not publicly held or with an entity which is their principal employer to disclose their salaries. The result of such a required disclosure, these commenters stated, would be to discourage some experienced business leaders from accepting executive positions with utilities which could benefit in a positive way from their experience.[18]

In view of these comments, the Commission is persuaded, for the time being, to delete the requirement that interest and compensation be disclosed under this final rule. However, the Commission has the discretion to inquire at a later time about interest and compensation. Although compensation received by the person filing may be significant in appraising the nature of the business relationship between the interlocked entities, the Commission does not believe that this information should be required as part of the routine filing. In the event the Commission finds that certain interlocking positions should be investigated, it may at that time take appropriate steps to obtain disclosure of interest or compensation.

In view of the above discussion, the Commission further believes that there is no reason to exclude, as suggested by commenters, privately held entities or entities which are the principal employers of persons holding interlocking positions.

In view of the decision to delete the compensation disclosure requirement the remaining comments regarding the $10,000 floor, specific kinds of compensation, and the nature of the interest in the covered entities need not be addressed.

E. Filing Requirements: Other Information

The proposed rule required that the following information be reported: the name and business address of the person reporting, the duties for the executive positions held, the nature of the business relationship between the public utility and the other interlocked entity, and the nature and an indication of the level of interest in and compensation received from both entities.

Several commenters suggested that the content of the statement as proposed be substantially reduced to require merely identification of the person holding the interlocking positions and the interlocking entities. American Public Power Association, in contrast, suggested that additional information be reported, *i.e.*, specific transactions, if any, between the person filing the statement and the interlocked entities. Cincinnati Gas & Electric Company argued that material business transactions between the entities be disclosed.

In this final rule, the Commission has modified the contents of the written statement. This modification applies not only to the disclosure of the amount of the interest and compensation but also to the disclosure of the nature of any interest in or compensation received from the interlocked entities.

Other changes were made so that the final rule now requires the following information: Name and business address of the person filing; identification of the public utilities and other covered entities involved; and identification of the interlock. In addition, the following information is to be provided if the interlock includes an entity producing or supplying electrical equipment for the use of the interlocked public utility:

(1) The aggregate amount of revenues received by such entity from producing or supplying electrical equipment to the interlocked public utility in the subject calendar year (§ 46.6(d)) in $100,000 increments; and

(2) The nature of the business relationship between the interlocked entities.

By this modification, the Commission decided to focus the filing requirement more directly on the relationship between the interlocked entities rather than on the person holding the interlocking positions.

The Commission believes that it has the discretion under section 305(c) as well as under its general information gathering authorities under the Act to inquire further, as some commenters suggested, regarding the interlocked entities and the person filing the statement. However, the Commission does not choose, at this time, to exercise its discretion to the fullest extent possible.

Regarding the above-mentioned suggestion by American Public Power Association to inquire about transactions between the person holding the interlocking positions and the interlocked entities, the Commission believes this information could be significant in evaluating the nature of the relationship between interlocked entities. Rather than require this information *ab initio*, the Commission has decided to make this inquiry on a case-by-case basis if circumstances surrounding certain interlocked entities indicate that closer scrutiny is needed.

Requiring this information, although of interest, would not be consistent with the objective of the Commission in promulgating these rules; namely, to require only the information necessary to adequately discharge its duties under section 305(c). If information disclosed in the statement indicates that further investigation is necessary, the Commission is free to inquire as to specific transactions between such person and either or both of the interlocked entities. At the outset, however, the Commission is not convinced that this additional inquiry is necessary.

Lastly, the rule has been revised to require the following additional information where pertinent: the docket number and the date the interlocking positions covered under Part 46 were authorized by the Commission under Part 45. This information merely serves as a cross-reference to the section 305(b) authorizations.

V. Effective Date

There is a statutory deadline of April 30, 1980, for compliance with these regulations. The Commission therefore finds good cause under 5 U.S.C. 553(d) to make the rules promulgated in this order effective immediately.

These rules have been promulgated under the Federal Power Act, as amended by PURPA, and, therefore, a right to rehearing exists under section 313 of the Federal Power Act.

(Federal Power Act, as amended, (16 U.S.C. 792–828c); Public Utility Regulatory Policies Act of 1978, (16 U.S.C. 2601–2645); Department of Energy Organization Act, (42 U.S.C. 7101–7352); E.O. 12009, 3 CFR 142 (1978).)

In consideration of the foregoing, the Commission amends Part 46 to Subchapter B, Chapter I, Title 18 of the Code of Federal Regulations, as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

— Footnotes —

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[1] The term "executive positions" as used in these regulations means any partner, appointee, representative, director, chief executive officer, president, vice president, secretary, treasurer, general manager, comptroller, chief purchasing agent, or any position for which a person performs a similar executive duty or function. The term

"interlocking positions" is used to refer to executive positions held by a person in both a public utility and one of the other section 305(*c*) entities.

[2] The term "entities" includes the category of purchasers identified in accordance with Order No. 67, see note 4 and accompanying text, as the largest purchasers of each public utility in terms of kilowatt-hours purchased at retail for each year of a three year period.

[3] 44 FR 66205 (November 19, 1979).

[4] 45 FR 3569 (January 18, 1980). On January 21, and February 4, 1980, notices were issued correcting minor technical errors in § 46.2 (a) and (c) and § 46.3(a). 45 FR 6377; 45 FR 9729.

[5] Section 305(b) has been implemented by Part 45 of the Commission's Regulations.

[6] Section 305(c) is being implemented by this final rule to be included in Part 46 of the Commission's Regulations.

[7] This definition is set forth in Order No. 67, 45 FR 3568, 3569 (January 18, 1980). The phrase "which includes a registered holding company" was inadvertently omitted from this definition and was subsequently added by an errata notice which was issued on February 4, 1980, 45 FR 9729 (February 13, 1980).

[8] *Dairyland Power Cooperative*, 37 FPC 12 (1967); *Salt River Project Agricultural Improvement and Power District* v. *Colorado Ute Electric Assoc.*, 37 FPC 68 (1967), *aff'd sub nom. Salt River Project Agricultural Improvement and Power District* v. *FPC*, 391 F.2d 470 (D.C. Cir. 1968).

[9] 15 U.S.C. 80a–2.

[10] 12 U.S.C. 1841.

[11] 15 U.S.C. 796.

[12] 26 U.S.C. 368.

[13] The word "business" was deleted from the term "business entity" in accordance with several comments as it is an unnecessary qualification for "entity."

[14] 13 U.S.C. 224.

[15] Examples of other items in the referenced accounts which do not qualify as "electrical equipment" are fire alarms, atmospheric measuring devices, and batteries.

[16] Note that this definition would bring within the coverage of this rule, a bank which leases nuclear fuel to a public utility. A person holding interlocking positions with such bank and such utility would have to comply with this rule.

[17] Gulf Power Company, Duke Power Company, Consolidated Edison Company of New York, Cincinnati Gas & Electric Company, Public Service Middle South Utilities, Sullivan & Cromwell, Central Illinois Light Company, Dayton Power & Light Company, EEI, and Alabama Power. Detroit Edison also suggested that each entity refer to its by-laws for a definition of "officer" or "director" eliminating the need for related definitions in the rule.

[18] Comments filed by Mr. C. Malcolm Davis discussed the problem of lack of experienced persons willing to serve on the boards of utilities.

[¶ 30,141]

45 F. R. 23684 (April 8, 1980)

18 CFR Part 294

[Docket No. RM79-52]

Interim Procedures for Shortages of Electric Energy and Capacity Under Section 206 of the Public Utility Regulatory Policies Act of 1978; Amendment To Extend Interim Regulations

AGENCY: Federal Energy Regulatory Commission.

ACTION: Amendment to extend interim regulations.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts regulations which extend, through a period ending April 30, 1981, its interim regulations implementing accommodation and reporting procedures for shortages of electric energy and capacity, under section 206 of the Public Utility Regulatory Policies Act of 1978. This Order extends the effectiveness of the interim regulations, and make no other changes. Under the regulations, each public utility now serving firm power wholesale customers must report to the Commission, the utility's customers, and appropriate State authorities, any shortages of electric energy or capacity anticipated to occur prior to April 30, 1981. Also, the regulations require each public utility to report any modifications of its plans for accommodating shortages which may occur before April 30, 1981.

EFFECTIVE DATE: April 1, 1980.

FOR FURTHER INFORMATION CONTACT:

Bernard B. Chew, Office of Electric Power Regulation, 825 North Capitol Street, N.E., Room 504RB, Washington, D.C. 20426, (202) 376-9264.

Christine P. Benagh, Division of Regulatory Development, Office of General Counsel, 825 North Capitol Street, N.E., Room 3331-A, Washington, D.C. 20426, (202) 275-4932.

Issued April 1, 1980.

Before Commissioners: Charles B. Curtis, Chairman; Georgiana Sheldon, Matthew Holden, Jr., and George R. Hall.

On June 15, 1979, the Commission issued interim regulations implementing, in part, section 206 of the Public Utility Regulatory Policies Act of 1978 (PURPA).[1] Section 206 of PURPA amended the Federal Power Act to direct the Commission to require, by rule, public utilities to report to the Commission and to appropriate State authorities anticipated shortages of electric energy or capacity and to submit to the Commission and to appropriate State authorities contingency plans to accommodate any shortages of electric energy or capacity.

Paragraph (b) of the interim regulations requires each public utility serving firm power wholesale customers to submit by July 23, 1979, "a brief statement indicating how it would accommodate any shortages of electric energy or capacity affecting its firm power customers, should such a shortage occur prior to September 30, 1979."[2]

Paragraph (c) of the interim regulations requires each utility to report immediately any shortage of electric energy or capacity which the utility anticipates will occur. In that report the utility must provide the Commission with certain information, including information regarding any procedures for accommodating a particular shortage, if they differ from the procedures set out in the utility's statement submitted pursuant to paragraph (b) of the interim regulations.

Prior to this Order, paragraph (a) defined "anticipated shortages of electric capacity or energy" as those situations which would result in shortages "anticipated to occur prior to April 30, 1980."[3] The purpose of this amendment is to extend the reporting requirements for a period ending April 30, 1981, so that the Commission will be advised of any anticipated shortages which may occur during the coming year while responses to a Notice of Inquiry to be issued in connection with this Order are being made and considered.

Accordingly, the Commission hereby amends the interim regulations as follows: first, the reporting requirements of paragraph (c) are extending through April 30, 1981, by amending the definition of "anticipated shortages of electric energy or capacity" in paragraph (a) to include those situations anticipated to occur prior to April 30, 1981. Second, if a plan to accommodate a shortage occurring prior to April 30, 1981, differs from the plan submitted pursuant to paragraph (b) of the interim regulations, the utility is hereby required to file a supplemental statement setting forth those changes. A utility need not file a statement of its plan to accommodate shortages prior to April 30, 1981, if that plan does not vary from that set out in the statement already filed pursuant to § 294.101(b).

(Public Utility Regulatory Policies Act of 1978, Pub. L. 95-617, 92 Stat. 3117 (1978); Federal Power Act, 16 U.S.C. § 792 et seq.; Exec. Order No. 12,009, 3 CFR 142 (1978); Administrative Procedure Act, 5 U.S.C. § 553)

In consideration of the foregoing, Part 294 of Subchapter K, Chapter I, Title 18 of the Code of Federal Regulations is amended as set forth below, effective immediately.

By the Commission.

Lois D. Cashell,
Acting Secretary.

— Footnotes —

[1] Interim Regulations, 18 CFR, § 294.101 (1979), Docket No. RM79-52 (issued June 15, 1979), issued under the Federal Power Act, 16 U.S.C. § 824a(g) (Supp. II, 1978), as amended by PURPA, § 206(a), Pub. L. 95-617, 92 Stat. 3117 (1978).

[2] This language was adopted by an Amendment to Interim Regulations, 44 FR 46455 (Aug. 8, 1979), Docket No. RM79-52 (issued August 1, 1979), in order to make clear the Commission's intent that all public utilities serving firm customers must submit statements concerning the methods by which they accommodate possible shortages. Before this amendment, the language appeared to suggest that only those utilities which anticipated shortages prior to September 30, 1979, were obliged to file accommodation reports under seciton 206(a) of PURPA.

[3] This date was initially September 30, 1979, but was extended to April 30, 1980, by Interim Regulations, 44 FR 61953 (Oct. 29, 1979), Docket No. RM79-52 (issued Oct. 23, 1979).

[¶ 30,142]

45 F. R. 21216 (April 1, 1980); 45 F. R. 80816 (December 8, 1980)

18 CFR Parts 0, 1, 2, 3, 157, 284, 375, 376

[Docket No. RM80–45]

Recodification of Rules Reflecting the Establishment of the FERC and Certain Rules Concerning Its Operation

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The purpose of this rule is to promulgate permanent rules concerning the Commission, its establishment, organization, mission, and functions and to revoke obsolete provisions promulgated by the FPC. The Commission has relied on many of the FPC rules since its creation, with additional necessary procedural provisions of its own placed in Part 0.

The recodification moves to Subchapter W, and restates many of the provisions basic to the Commission's operation currently contained in Subchapter A. A new Subpart A is added to Part 1 and contains definitions applicable to all Commission rules and regulations.

The changes in this final rule do not alter any legal requirement of the Commission's regulations; the changes only conform the procedures of the Commission to existing law and practice and begin the process of reorganizing the regulations for clarity.

EFFECTIVE DATE: Because this is a rule of agency organization, procedure and practice, it is effective March 28, 1980.

FOR FURTHER INFORMATION CONTACT: MaryJane Reynolds, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8000–E, 825 North Capitol Street NE., Washington, D.C. 20426 (202) 357–8455.

March 28, 1980.

I. Background

The Federal Energy Regulatory Commission ("Commission") was created by Title IV of the Department of Energy Organization Act ("DOE Act"). In accordance with that statute the Commission has assumed many of the responsibilities of the Federal Power Commission ("FPC").[1]

Shortly after its creation, interim regulations were promulgated setting forth the functions, powers and duties of the newly created FERC 18 CFR, Part 0. For other operational and internal rules, the Commission has temporarily relied upon FPC rules (*e.g.*, the FERC has used the FPC Sunshine rules.) The purpose of this rule is to promulgate permanent rules concerning the Commission, its establishment, organization, mission, functions and method of operation and to revoke obsolete provisions promulgated by the FPC.

The new regulations are codified in Parts 375 and 376. Part 375 sets forth rules governing the Commission *per se*. Subpart A concerns the establishment of the Commission, custody of records, the official seal, and transcripts, proceedings from other agencies and attendant provisions. Subpart A is essentially a recodification of Subpart O. Subpart B sets forth the procedures for Commission meetings under the Government in the Sunshine Act: it is essentially a recodification of the FPC Sunshine rule set forth in its § 1.3a. Subpart C recodifies the delegations of authority to certain office heads. Those delegations were previously found in § 3.5

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[1] It also acquired certain responsibilities from the Interstate Commerce Commission ("ICC") with regard to establishing oil pipeline rates under the Interstate Commerce Act. In addition, the Commission was given responsibility to review certain actions of the Secretary of the Department of Energy. Subsequently Congress has passed additional legislation expanding the responsibilities of the Commission.

Part 376 sets forth the organization, mission, and functions of the Commission and certain provisions concerning operations during emergency conditions. These rules replace provisions previously found in Part 3 of the regulations.

These rules also add a new Subpart A to existing Part 1. This subpart will contain definitions generally applicable to all of the provisions of the Commission codified in Title 18 of the Code of Federal Regulations. Presently it is limited to definitions of the terms in the new Parts 375 and 376. Subpart A also contains rules of construction of terms used in the regulations.

II. Summary

Following is a Cross-reference table. It shows the derivation by old section number, for the new regulations.

Regulation	Derivation (references are to present regulations unless otherwise specified)
Subpart A	
§ 375.101:	
(a)	§ 0.1; § 0.2; § 3.2; Sec. 401(a) DOE Act.
(b)	§ 0.4(a); first sentence of § 1.1(a)(2); § 3.6(a).
(c)	§ 1.1(b).
(d)	Sec. 401(b), DOE Act; § 1.1(c).
(e)	Sec. 401(e) DOE Act; § 1.1(d).
(f)	Sec. 401(f), DOE Act; § 1.1(e).
§ 375.102:	
(a)	§ 1.2(a).
(b)	§ 1.2(b).
§ 375.103	
§ 375.104	§ 0.3.
§ 375.105:	
(a)	§ 0.4(c).
(b)	§ 0.4(b).
(c)	§ 0.4(b), (d), (e), (f), (g), (i); § 1.2(c).
Subpart B	
§ 375.201	None.
§ 375.202:	
(a)(1)	§ 1.3a(a)(2).
(a)(2)	
(a)(3)	§ 1.3a(b).
(a)(4)	§ 1.3a(d).
(b)	§ 1.3a(b)(2).
§ 375.203:	
(a)	§ 1.3a(b)(1).
(b)	§ 1.3a(b).
(c)	§ 1.3a(c).
§ 375.204:	
Subpart B	
(a)	§ 1.3a(f)(1).
(b)	§ 1.3a(f)(2) Proviso.
(c)	§ 1.3a(f)(3).
(d)	§ 1.3a(f) (4), (5), and (6).
§ 375.205:	
(a)	§ 1.3a(d)(1).
(b)	§ 1.3a(d)(2).
§ 375.206:	
(a)	§ 1.3a(d)(3)(i).
(b)	§ 1.3a(d)(3)(ii).
(c)	§ 1.3a(d)(3)(iii).
(d)	§ 1.3a(e)(1).
(e)	§ 1.3a(e)(2).
(f)(1)	§ 1.3a(e)(5).
(f)(2)	§ 1.3a(e)(6).
Subpart C	
§ 375.301 through § 375.331	§ 3.5. § 0.5.
Part 376; Subpart A	
§ 376.101	§ 3.1.
§ 376.102	§ 3.2; § 3.4.
§ 376.103	§ 3.3.
§ 376.104	Subpart B of Part 3.
§ 376.105	Sec. 401(c) § 3.4(b).
Subpart B	
§ 376.201	§ 3.7(a).
§ 376.202	§ 3.7(b)(1).
§ 376.203	§ 3.7(b)(2).
§ 376.204:	
(a)	§ 3.7(c)(1).
(b)	§ 3.7(c)(3).
(c)	§ 3.7(c)(4).
§ 376.205	§ 3.7(c)(5).
§ 376.206	§ 3.7(c)(6), (d).
§ 376.207	§ 3.7(e).
§ 376.208	§ 3.7.(f).

III. Effective Date

Pursuant to section 553 of Title 5 of the United States Code, this rule is being issued without prior notice and comment because it is a rule of agency organization, procedure and practice. For the same reasons, and because the amendments to the regulations contained in this rule are necessary to conform the Commission's regulations to existing law and practices and to provide the public with essential new provisions respecting Commission practice, the Commission finds good cause to have the amendment of this rule made effective March 28, 1980.

(Department of Energy Organization Act, 42 U.S.C. 7101–7352; E.O. 12009, 3 CFR 142 (1978); Administrative Procedure Act, 5 U.S.C. 553 (1977))

In consideration of the foregoing, Chapter I, Title 18 of the Code of Federal Regulations is amended as set forth below.

By the Commission.

Lois D. Cashell,
Acting Secretary.

[¶ 30,143]

45 F. R. 24124 (April 9, 1980)

18 CFR Part 274

[Docket No. RM79-3]

Determinations by Jurisdictional Agencies, U.S. Geological Survey and the State of Colorado Oil and Gas Conservation Commission Applications for Alternative Filing Requirements; Order Granting Application for Alternative Filing Requirements

Issued: April 3, 1980.

AGENCY: The Federal Energy Regulatory Commission.

ACTION: Order granting application for alternative filing requirements.

SUMMARY: On November 21, 1979, the Colorado Department of Natural Resources, Oil and Gas Conservation Commission (Colorado) and the United States Geological Survey (USGS) filed applications for approval of alternative filing requirements pursuant to § 274.207 of the Commission's regulations. The proposed alternative filing requirements sought jointly by Colorado and the USGS would enable operators to apply for eligibility determinations under section 103 of the Natural Gas Policy Act of 1978 (NGPA) for additional wells in existing proration units in the Fruitland-Pictured Cliffs, Mesaverde and Dakota-Morrison pools without repeated submissions of geological and engineering data to show that the additional well is necessary to effectively and efficiently drain the portion of the reservoir covered by a proration unit that cannot be effectively and efficiently drained by any existing well within the proration unit. In a separate application, Colorado seeks approval of similar alternative filing requirements applicable to persons seeking section 103 eligibility determinations for wells drilled in the "J"-Sand Formation of the Wattenberg Field.

The Commission finds that good cause exists to approve the applications for alternative filing requirements and accordingly amends § 274.208 to authorize the filing of applications under the alternative requirements submitted, for well category determinations for section 103 of the NGPA, where the subject wells qualify under the applicable State of Colorado Orders.

EFFECTIVE DATE: April 3, 1980.

FOR FURTHER INFORMATION CONTACT: Kenneth F. Plumb, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357–8400.

Before Commissioners: Charles B. Curtis, Chairman; Georgiana Sheldon, Matthew Holden, Jr., and George R. Hall.

On November 21, 1979, the Colorado Department of Natural Resources, Oil and Gas Conservation Commission (Colorado) and the United States Geological Survey (USGS) filed applications for approval of alternative filing requirements pursuant to § 274.207 of the Commission's regulations. The proposed alternative filing requirements sought jointly by Colorado and the USGS would enable operators to apply for eligibility determinations under section 103 of the Natural Gas Policy Act of 1978 (NGPA) for additional wells in existing proration units in the Fruitland-Pictured Cliffs, Mesaverde and Dakota-Morrison pools without repeated submissions of geological and engineering data to show that the additional well is necessary to effectively and efficiently drain the portion of the reservoir covered by a proration unit that cannot be effectively and efficiently drained by any existing well within the proration unit. In a separate application, Colorado seeks approval of similar alternative filing requirements applicable to persons seeking section 103 eligibility determinations for wells drilled in the "J" Sand Formation of the Wattenberg Field.

Section 103 of the NGPA establishes the maximum lawful price for natural gas produced from new, onshore production wells. Under § 271.305(b) of the Commission's regulations, a well drilled on or after February 19, 1977, in an existing proration unit may qualify for the section 103 price if the jurisdictional agency finds that the well is necessary to effectively and efficiently drain that portion of the reservoir covered by the proration unit.

An applicant seeking a determination of eligibility under § 271.305(b) to collect the section 103 price is required to file with the appropriate jurisdictional agency the information specified in § 274.204 of the Commission's regulations. Under § 274.204(f), an applicant must submit, on a well-by-well basis, geological evidence and engineering data that an additional well within an existing proration unit is necessary to effectively and efficiently drain a portion of the reservoir covered by the proration unit, which cannot be effectively and efficiently drained by any existing well within the proration unit. However, a jurisdictional agency is authorized under § 274.207 to apply for Commission approval of alternative filings requirements.

The application of Colorado and USGS for approval of alternative filing requirements is based on the State of Colorado's Order No. 112–46, as ratified by the USGS Oil and Gas Supervisor for the Southern Rocky Mountain Area, which authorizes an infill well drilling program for the Fruitland-Pictured Cliffs, Mesaverde, and Dakota-Morrison pools. Order No. 112–46 permits the drilling of an additional well in the undrilled quarter-section of existing 320-acre proration units, and also permits the drilling of three additional wells in the undrilled quarter-sections of existing 640-acre proration units in the Ignatio Blanco Field, La Plata and Archuleta Counties, Colorado. Well locations are required to be no closer than 990 feet to the boundaries of the quarter-section upon which it is located, and in cases of fractional sections, no closer than 990 feet from another well producing from the same formation. Exceptions may be granted due to topographical or surface hazards, or for other reasons, provided the owners of the contiguous and cornering units toward which the proposed location would be moved, file a waiver, or consent in writing to the exceptions. The Colorado order also rescinded a provision found in a former field order which required the consolidation of all interests in a drilling and spacing unit by a pooling agreement prior to the drilling of a well.

Colorado and USGS have concluded that the data upon which the drilling program is based, which was collected under oath at hearing, provides substantial evidence for finding that a well drilled in compliance with Colorado Order No. 112–46 is necessary to effectively and efficiently drain that portion of the reservoir covered by the existing proration unit. For that reason, Colorado and the USGS assert that it is unnecessary to require the submission of geological and engineering data in support of a section 103 eligibility determination for each well in the subject pool. Therefore, Colorado and the USGS propose to replace the requirement of § 274.204(f) with a statement by the applicant specifying the number of Colorado Order No. 112–46 authorizing an infill well drilling program on a field-wide basis.

Colorado additionally submitted a separate application for approval of alternative filing requirements for additional wells drilled pursuant to Colorado's Oil and Gas Conservation

Commission's Order No. 232–20. This order provides for optional drilling of an additional well in the undrilled quarter-section of each 320-acre drilling and spacing unit for production of gas from the "J" Sand underlying certain lands in the Wattenberg Gas Spaced Area. For those locations not presently included in a 320-acre unit, 160-acre units will be established. Well locations are required to be no closer than 990 feet to the boundaries of the quarter section. On the basis of evidence accumulated under oath at hearing, Colorado has found that there exists substantial evidence to conclude that wells in compliance with Order No. 232–20 are necessary for effective and efficient drainage.

In support of their applications, Colorado and USGS have submitted to the Commission the evidence relied on in adopting the field-wide drilling programs. The Commission has reviewed the information submitted with the applications, and finds that the proposed alternative filing requirements will provide sufficient information upon which determinations under section 103 of the NGPA can be based. Accordingly, the Commission is amending Part 274, Subpart B, in § 274.208 to adopt the alternative filing requirements proposed by Colorado and the USGS for wells drilled pursuant to Colorado's Order No. 112–46, and to adopt the alternative filing requirements proposed by Colorado for determinations made by Colorado for wells drilled pursuant to Colorado Order No. 232–20.

The Commission's regulations in § 271.305 (b) and (c) require jurisdictional agencies to notify the Commission when findings are made under § 271.305 that an additional well in an existing proration unit is necessary for efficient and effective drainage. Since Colorado's Order No. 112–46, as ratified by the USGS, and Colorado's Order No. 232–20 find that infill drilling of additional wells on established proration units is necessary on a field-wide basis for effective and efficient drainage of portions of the reservoir covered by proration units which cannot be effectively and efficiently drained by any existing wells within those units, the Commission finds that it is unnecessary for Colorado and USGS to notify the Commission on an individual well basis that the effective and efficient drainage finding has been made. Accordingly, the Commission is waiving the requirements of § 271.305 (b) and (c) with respect to determinations made by Colorado or USGS for wells drilled pursuant to Colorado's Order No. 112–46, as ratified by USGS. Such requirements are also waived with respect to determinations made by Colorado for wells drilled pursuant to Order No. 232–20.

Further, § 274.204(d)(4) requires the filing of an oath statement that the applicant's conclusion that the natural gas for which he seeks a determination is produced from a new, onshore production well is based on documents submitted in the application. The oath statement must be modified for wells covered by the alternative filing requirements inasmuch as the applications will not contain all the documents relied upon in making the determination. Therefore, the phrase "documents submitted in the application" will be deleted from the oath statement, as applicable to persons seeking section 103 eligibility determinations for wells within the subject pools.

Public Procedures and Effective Date

A notice regarding the USGS and Colorado applications was issued on December 21, 1979. (44 FR 77252; December 31, 1979) The Commission stated that comments on the proposed alternative filing requirements filed by January 7, 1980, would be considered by the Commission. No comments were received. In view of the above discussion, the Commission approves the alternative filing requirements submitted by Colorado and USGS and waives the provisions of § 271.305 (b) and (c) and § 274.204(d)(4) as noted above. The Commission believes that good cause exists to make the alternative filing requirements effective immediately for all determinations

which have not yet become final under § 275.202 as of the day before the date of issuance of this order.

(Natural Gas Act, as amended, 15 U.S.C. § 717 *et seq.;* Department of Energy Organization Act, 42 U.S.C. § 7107 *et seq.;* Exec. Order No. 12009, 42 FR 46267; Natural Gas Policy Act of 1978, 15 U.S.C. § 3301 *et seq.*)

In consideration of the foregoing, Part 274 of Subchapter H, Chapter I, Title 18, Code of Federal Regulations is amended as set forth below, effective immediately.

By the Commission.

Lois D. Cashell,
Acting Secretary.

[¶ 30,144]

45 F. R. 26694 (April 21, 1980)

18 CFR Part 375

[Docket No. RM79-59; Order No. 38-C]

Delegation of the Commission's Authority to the Director of the Office of Pipeline and Producer Regulation

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts a rule that delegates to the Director of the Office of Pipeline and Producer Regulation the Commission's authority: (1) To compute maximum lawful prices prescribed under Title I of the Natural Gas Policy Act of 1978 (NGPA) and the monthly equivalent of the annual inflation adjustment factor; (2) to compute the incremental pricing threshold prescribed under Title II of the NGPA; and (3) to publish such prices, factor, and threshold in the Federal Register. The authority granted by the regulation applies to the computation and publication of prices for those categories of natural gas described in sections 102, 103, 104, 106(a), 106(b)(1)(B), 107(c), 108, and 109 of the NGPA.

DATES: Effective April 7, 1980. Written comments by April 30, 1980.

ADDRESS: Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Tom Runge, Office of the General Counsel, 825 North Capitol Street, NE., Room 3329, Washington, D.C. 20426, (202) 357-8318.

A. Background

The Federal Energy Regulatory Commission (Commission) administers most provisions of the Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, (NGPA) including those pertaining to maximum lawful prices for first sales of natural gas and the incremental pricing program required under Title II of the NGPA. Section 501(a) of the NGPA authorizes the Commission to issue rules and orders under the Act and to perform any and all acts it may find necessary or appropriate to carry out the provisions of the NGPA.

On August 14, 1978, the Commission approved a rulemaking, Delegations of Authority (Phase I), Docket No. RM78-19 (43 FR 36433, (August 17, 1978)) which served to transfer annually over 7,000 decisions of a largely routine and ministerial nature downward within the Commission, to its various office directors, so that the Commission can concentrate its major efforts on issues of greater significance. Subsequently, on July 23, 1979, the Commission added to these delegations by adopting additional ones, in the Phase II Delegation, Docket No. RM79-59, (44 FR 46449, (August 8, 1979)).

To aid in the Commission's implementation of the NGPA, the Commission has decided to approve a further delegation of authority to the Director of the Office of Pipeline and Producer Regulation. The power hereby delegated is the authority to compute and publish maximum lawful prices and the monthly equivalent of the annual inflation adjustment factor pursuant to Title I of the NGPA, and the threshold prices required for implementation of the incremental pricing program. These powers, even more than most other delegated authorities, are purely routine and mechanical in nature. Only mathematical calculations based on various formulas are required. No discretionary decisionmaking on the part of the office director is involved.

B. Summary of Rule

Under revised § 375.307, there is delegated to the Director of the Office of Pipeline and Producer Regulation the authority to compute, pursuant to section 101(b)(6) of the NGPA, maximum lawful prices prescribed under Title I of the Act and the monthly equivalent of the annual inflation adjustment factor at least five days before the beginning of any month to which such figures apply, and to publish such prices and such factor in the **Federal Register** as soon as possible thereafter. The authority herein granted applies to the computation and publication of prices for those categories of natural gas described in sections 102, 103, 104, 106(a), 106(b)(1)(B), 107(c), 108, and 109 of the NGPA.

There is also delegated to the Director the authority to compute the incremental pricing threshold, pursuant to section 203(c) of the NGPA. The Director is also delegated the authority to publish this threshold, along with the thresholds for natural gas described in sections 203(a)(5), 203(a)(6), 203(a)(7), and 203(a)(8) of the NGPA, in the **Federal Register**, in accord with § 282.304 of the Commission's regulations. (The thresholds for gas described in sections 203(a)(5)–(8) are either maximum lawful prices, as computed pursuant to Title I, or are computed by the Energy Information Administration of the Department of Energy and furnished to the Commission.)

C. Effective Date

The Commission hereby makes this regulation effective immediately upon issuance of this order. The regulation concerns agency practice and procedure; accordingly, pursuant to 5 U.S.C. 553 (b) and (d), public notice and comments are not required. The Commission, nevertheless, invites interested members of the public to submit comments regarding this new delegation. The Commission and its staff will evaluate any information received from interested persons and will consider appropriate revisions to these regulations based on comments received. An original and 14 copies should be filed by April 30, 1980, with the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. All comments should refer, on the cover page, to Docket No. RM79-59.

(Natural Gas Act, as amended, (15 U.S.C. 717 *et seq.*); Department of Energy Organization Act, (42 U.S.C. 7107 *et seq.*), Natural Gas Policy Act, Pub. L. 95-621, 92 Stat. 3350; E.O. 12009, 42 FR 46267)

For the reasons stated herein, Part 375 of Subchapter W of Chapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,145]

45 F. R. 28085 (April 28, 1980)

18 CFR Part 1

[Order No. RM80-51; Order No. 77]

Rules of Practice and Procedure; Regulations Providing for Standard Format for and Summary of Briefs on and Opposing Exceptions

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission amends

§ 1.31(b) of its Rules of Practice and Procedure to standardize the format of briefs on exceptions and briefs opposing exceptions, and to require that brief writers submit a summary of their briefs on or opposing exceptions along with the brief.

The purpose of providing a standard format for briefs on or opposing exceptions is to enable the Commission to more effectively review the legal, factual, and policy issues that are presented in the many cases that come before it for decision.

EFFECTIVE DATE: June 20, 1980.

FOR FURTHER INFORMATION CONTACT:

Deborah Gottheil, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357–8457.

June Perin, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357–8473.

SUPPLEMENTARY INFORMATION:

Issued: April 21, 1980.

The Commission is amending § 1.31(b) of its Rules of Practice and Procedure to standardize the format of briefs on exceptions and briefs opposing exceptions, and to require that brief writers submit a summary of their brief on exceptions or brief opposing exceptions long with the brief. The purpose of this amendment is to make briefs on exceptions and briefs opposing exceptions more useful to the Commission. The amendment adopts several recommendations contained in the Chairman's *Report to Congress*, drafted pursuant to section 207 of the Public Utility Regulatory Policies Act of 1978.[1]

The amendment provides that each brief on exceptions and brief opposing exceptions must include a discussion of the brief writer's arguments with references to the pages of the record or exhibits where the evidence appears in support of such arguments. In addition, the briefs must be accompanied by a separate summary of the brief, not more than 5 pages in length. There is no prescribed format for this summary. It may contain any discussion or arguments that the brief writer believes the Commission will consider persuasive.

The amendment provides separate yet additional requirements for briefs on or opposing exceptions. Briefs on exceptions must include a short statement of the case, a list of the errors of fact or law asserted, and a concise discussion of the policy considerations that warrant Commission review. Briefs opposing exceptions must include a list of the exceptions that are being opposed and a rebuttal to the policy considerations that were claimed to warrant Commission review.

The purpose of providing a standard format for briefs on or opposing exceptions is to enable the Commission to more effectively review the legal, factual, and policy issues that are presented in the many cases that come before it for decision. Those who practice before the Commission should realize that the interests of the Commission, and ultimately their clients, will be served by adhering to the prescribed format. Accordingly, the rule provides that briefs on or opposing exceptions that are not in compliance with the regulation risk being rejected or disregarded by the Commission.

Since this rule concerns a matter of agency practice and procedure, notice and public procedure thereon is unnecessary pursuant to 5 U.S.C. 553(b). This amendment applies to briefs on exceptions and briefs opposing exceptions filed 60 days after issuance of the regulation, or thereafter.

(Federal Power Act, as amended, 16 U.S.C. § 792, *et seq.*, Natural Gas Act, as amended, 15 U.S.C. § 717 *et seq.*, Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.*, E.O. 12009, 42 Fed. Reg. 46267)

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[1] C. Curtis, Chairman, FERC, *Decisional Delay in Wholesale Electric Rate Cases: Causes, Consequences, and Possible Remedies.* (January 23, 1980)

In consideration of the foregoing, the Commission amends Part 1 of Chapter I, Title 18, Code of Federal Regulations, as set forth below, effective June 20, 1980.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,146]

45 F. R. 28085 (April 28, 1980)

18 CFR Part 4

[Docket No. RM79-35; Order No. 76]

Exemptions of Small Conduit Hydroelectric Facilities From Part I of the Federal Power Act

AGENCY: The Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: This rule implements section 213 of the Public Utility Regulatory Policies Act of 1978 which added section 30 to the Federal Power Act which gives the Commission authority to exempt from Part I of the Federal Power Act certain hydroelectric facilities which have an installed capacity of 15 megawatts or less. The rule sets forth the eligibility requirements and the application procedures for obtaining the exemption for such a hydroelectric facility.

EFFECTIVE DATE: May 19, 1980.

FOR FURTHER INFORMATION CONTACT:

Colette K. Bohatch, Federal Energy Regulatory Commission, Office of the General Counsel, Room 3335, 825 North Capitol Street, N.E., Washington, D.C. 20425, (202) 357-8606.

Glenn J. Berger, Federal Energy Regulatory Commission, Office of the General Counsel, Room 8100, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8033.

Howard Jack, Federal Energy Regulatory Commission, Office of the General Counsel, Room 8608, 825 North Capitol Street, N.E., Washington, D.C. 20526, (202) 357-~~8448~~.

Ron Corso, Federal Energy Regulatory Commission, Office of Electric Power Regulations, Room 4400, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-4864.

Final Rule Under Section 213 of The Public Utility Regulatory Policies Act of 1978

Issued: April 18, 1980.

The Federal Energy Regulatory Commission (Commission) gives notice that it adopts regulations that provide procedures for exemptions from Part I of the Federal Power Act (Act) for hydroelectric facilities with installed capacity of 15 megawatts or less that are built on non-Federal lands and utilize the hydroelectric potential of a manmade conduit operated primarily for purposes other than the generation of power. The rule informs applicants for such exemptions about the information required for the Commission to make an informed decision.

I. Background

Section 213 of the Public Utility Regulatory Policies Act of 1978 (PURPA) added section 30 to the Act, which gives the Commission authority to exempt small conduit hydroelectric facilities from regulation under Part I of the Act. Proposed regulations for implementation of section 30 were issued by the Commission on April 20, 1979.[1]

The Commission originally proposed an exemption process with a minimum of filing requirements and an expedited procedure, which, pursuant to comments received, has been further streamlined. Under the final rule, applications will be considered on a case-by-case basis.

The final rule sets forth regulations which will expedite exemption from Part I of the Act while ensuring that the Commission obtains sufficient information to discharge its regulatory obligations under sections 213 of PURPA and the National Environmental Policy

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[1] 44 FR 24560 (April 20, 1979).

Act of 1969 (NEPA), among other statutes. These application requirements are substantially less than those for license applications for minor projects (up to 1.5 megawatts) provided in § 131.60 of the Commission's regulations.[2]

To be eligible for exemption under section 30, a facility must:

(1) be constructed, operated, or maintained for the generation of electric power;

(2) utilize for the generation of electric power only the hydroelectric potential of a manmade conduit operated primarily for distribution of water for purposes other than the generation of electricity;

(3) have an installed capacity no greater than 15 megawatts; and

(4) be located on non-Federal lands.

Any citizen, association of citizens, municipality, State, corporation incorporated under the laws of the United States or a State, may apply for exemption for such a facility.[3] The application and the procedures provided in the rule were designed to encourage the development of hydroelectric facilities that utilize available but undeveloped hydroelectric potential of manmade conduits.

An exemption application must contain the following items, each designed to require a minimum of information necessary to ascertain the eligibility of the facility, its impact on the environment, and whether the requested exemption is in the public interest:

(1) An introductory statement;

(2) Exhibit A, a description of the existing or proposed facility and mode of operation;

(3) Exhibit B, a general location map;

(4) Exhibit E, an environmental report; and

(5) Exhibit G, a set of drawings showing specific structures of the facility.

The Commission believes that the abbreviated application will permit it, in most instances, to render a decision on an exemption application within 90 days. Accordingly, the rule provides an automatic exemption for any application that is not acted upon within 90 days after it has been accepted for filing.

Although the rule also provides that the Commission may suspend the 90-day period to conduct a hearing on the application or to further deliberate the merits of an application, the Commission believes that the 90-day period will not, in most cases, be extended.

In the event an exemption application is denied, an applicant may request that such application be converted into a license application. The applicant can complete the license application merely by supplying any additional information required by the pertinent license regulations, while retaining the filing date awarded to the exemption application. This will further lessen the applicant's filing burden, if licensing is necessary.

II. Comment Analysis

Twelve parties commented on the rule, including the United States Department of Agriculture (USDA) and the United States Department of the Interior (DOI). Several State and local government agencies commented, among them the City of San Diego, California Energy Resources Conservation and Development Commission (CERCDC), Metropolitan Water District of Southern California (Metropolitan), Santa Clara Water District, and the Power Authority of the State of New York (PASNY). Comments were also filed by public utilities, including Central Power and Light Company (Central Power) and Pacific Power and Light Company (Pacific). The Association of California Water

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[2] For example, mapping requirements for an exemption application are less stringent than those for a license application for a minor project.

[3] The Commission has already exempted the following projects from the requirements of Part I of the Act pursuant to its section 30 authority: Project No. 2806, Metropolitan Water District of Southern California, exemption granted on August 16, 1979; Project No. 2878, Turlock Irrigation District, exemption granted September 12, 1979; Project No. 2871, Turlock Irrigation District, exemption granted, November 16, 1979.

Agencies (ACWA), the National Conference of State Legislatures and the Puerto Rico Water Authority also filed comments.

A. *General Approach.* The case-by-case approach to the application procedures set forth in this rule was the subject of comment submitted by Metropolitan, who suggested that the Commission reconsider a generic exemption. After reconsidering the generic approach the Commission has decided to retain the case-by-case approach.

The leading factor underlying this decision is that different facilities at different geographic sites may have different effects. Environmental surroundings, as well as the construction and operation for each project, may vary considerably. The Commission is charged under several statutes, including NEPA, with the responsibility to assess the environmental implications of its actions. This can be accomplished more effectively on a case-by-case, rather than generic, basis. A generic exemption would also diminish considerably the value of the interagency consultation that section 30 requires. After developing some experience in the administration of this rule, however, the Commission may reconsider the question of a generic exemption.

B. *Definitions.* Definitions were mentioned by more than half of the commenters. Terms of primary interest were "conduit," "constuction of a dam," and "small conduit hydroelectric facility."

Conduit. Comments on the definition of "conduit" were directed at the phrase "not primarily for the generation of electricity" as it related to the use of water flowing through the conduit. Several commenters suggested incorporating a water volume test to clarify "primarily," *i.e.,* only a specific volume of the water flowing through the conduit can be used for generation of electricity. Other commenters suggested a dollar value test as a means of comparing water use for distribution and water use for generation of electricity. Central Power and Pacific argued further that the definition "conduit" should be modified to accommodate circumstances in which the amount of water that ultimately is distributed for appropriate consumptive purposes is much less than the amount which must flow through the conduit to process the water for such consumptive purposes.

Although the Commission believes it would be helpful to provide some guidance for the term "primarily," these suggested tests are too restrictive. None of these tests, the dollar value of the water, the volume of water flowing through the conduit, nor the percentage of the water actually consumed should necessarily be the controlling factor in determining if a conduit facility is used primarily for agricultural, municipal, or industrial consumption. The Commission believes, however, that many of these cases can be decided by looking at the original purpose of the facility and how it is being operated. Therefore, the Commission, to give guidance in this area, has decided to describe this situation in the rule itself.

The Commission has determined that a conduit "which was built for the distribution of water for agricultural, municipal, or industrial consumption and is still operated for such a purpose, and to which a hydroelectric facility has later been or is proposed to be added," is "not operated primarily for the generation of electricity." This will reduce some of the uncertainty inherent in the term "primarily" for a substantial number of sites, without reducing the Commission's flexibility to assess on a case-by-case basis other facilities which may apply for the exemption.

Small Conduit Hydroelectric Facility. The proposed definition of "small conduit hydroelectric facility" was criticized by DOI and the Puerto Rico Water Authority, regarding the limitation on use of "Federal lands." Both noted that this limitation in the proposed rule differed from the limitation of section 30 of the Act, because the rule required that the facility not be located "in whole or in part on any public lands or reservations of the United States," while section 30 requires that the facility be located on "non-Federal lands."

After further consideration the Commission has amended the definition to require that the facility be located "entirely on non-Federal lands." The Commission has recently ruled that the term "non-Federal lands" in section 30 of the Act should be interpreted to refer to any land except land to which the United States holds fee title.[4] A definition for "non-Federal lands" incorporating this interpretation has been added to the rule, to provide maximum eligibility for exemption.

In addition, the Commission believes that the focus of the non-Federal lands limitation is the location of the hydroelectric facility itself, and not the location of the conduit. Thus, if a conduit to which the hydroelectric facility is attached crosses Federal lands, this fact alone would not disqualify an otherwise eligible hydroelectric facility from obtaining the exemption. If the hydroelectric facility is located on Federal lands, however, that facility would be ineligible for exemption. This clarification is reflected in the definition of "small conduit hydroelectric facility."

Several commenters also criticized this definition for its requirement that water used for power generation must be discharged into a conduit. Pacific based its comment upon its experience with three hydroelectric facilities, each of which discharges water into a natural stream for use in irrigation and domestic consumption. Pacific argued that these facilities, which might otherwise be eligible for the exemption, would be disqualified because water is discharged into a natural stream rather than a conduit. In addition, Metropolitan argued that the definition would disqualify facilities located at the end of the conduit which discharged water directly for agricultural, municipal, or industrial purposes, such as discharge into an agricultural field for irrigation or into a ground well settling basin.

In light of the comments submitted by Pacific and Metropolitan, the Commission has decided to modify the definition of "small conduit hydroelectric facility" to permit discharge of water directly for consumptive use or into a natural body of water that forms an intermediate part of a single qualifying water supply system.

The Commission will also consider applications for exemption from facilities which do not meet the water discharge requirement in § 4.91(f)(5), but only after the applicant has demonstrated in a waiver petition under § 1.7(b) of the regulations that the facility still meets the statutory test of using the hydroelectric potential of a conduit primarily used for agricultural, municipal, or industrial consumption purposes. The Commission believes that the number of facilities which would qualify under section 30, but not under § 4.91(f)(5) of the rule, is small. Therefore, notice and comment procedures in these circumstances should not begin until a petition for waiver is granted and the application is accepted for filing.[5] Thus, an application for such a facility must be accompanied by a petition for waiver and must note that fact in the "Introductory Statement" required by § 4.92(c)(2).

The Commission has also decided that primary transmission lines associated with the facility should not be considered part of the definition of "small conduit hydroelectric facility." Upon reexamination of section 30 of the Act, the Commission notes that an exemptable hydroelectric facility is one "constructed, operated, or maintained for the *generation* of electric power."

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[4] *South Columbia Basin Irrigation District*, Project No. 2926, Order Issuing License (Major) (issued March 27, 1980).

[5] The question of eligibility for exemption, under the statutory requirements, would remain subject to dispute in a proceeding on the application even if waiver were granted. Otherwise, potentially interested parties would be foreclosed from addressing the issue, because it would be finally decided before notice of application was even published.

Thus, transmission lines are not part of a small conduit hydroelectric facility within the meaning of the statute. This will increase the number of facilities eligible for exemption under the rule and further the purpose of section 30 of the Act.

The Commission has also amended the definition of "small conduit hydroelectric facility" to require that it not be "an integral part of a dam." Under this revised restriction, a facility will not be disqualified unless the powerhouse and the dam together form a physically and functionally indivisible unit for the impoundment of water.

Construction of a Dam. The definition of "construction of a dam" was also the subject of comment. ACWA and Metropolitan stated that any small conduit hydroelectric project which requires any modification of a dam under the Commission's proposed definition would be ineligible for the exemption.

This comment does not accurately apply the proposed rule. The definition of "construction of a dam" as proposed comprehended only construction, repair, reconstruction, or modification of a dam that: (1) creates a new impoundment or (2) increases the normal maximum surface elevation or the normal maximum surface area of an existing impoundment. The definition does permit other kinds of dam modifications.

The underlying reason for the exemption is to encourage development of power facilities associated with development of industrial, municipal, or agricultural water supply, where hydroelectric energy can be developed incidentally to the primary purpose of the conduit, *i.e.*, water distribution. The definition of "small conduit hydroelectric facility" has been modified, however, to make clear that "construction of a dam" that would occur for agricultural, municipal, or industrial consumptive purposes even without installation of hydroelectric generating facilities will not disqualify the hydroelectric facility from exemption.

Lastly, DOI stated that, as this definition was proposed, an exemption could be granted for construction of a large diversion dam for operation of a hydroelectric facility. Under the rule this could happen only if the diversion dam would have been built in any event for consumptive water supply purposes. In other words, the decision to construct the hydroelectric facility would not be the primary reason for constructing the diversion dam. There is no indication in the legislative history of PURPA that Congress intended to preclude an exemption unless the facility itself were structurally integrated with the dam or the dam created or enlarged an impoundment for hydroelectric generating purposes, and this rule would not permit an exemption in those circumstances.

C. *Scope of Exemption.* With respect to the scope of the exemption, Metropolitan presented extensive argument on the legislative history of section 213 of PURPA, contending that Congress intended to exempt not only a small conduit hydroelectric facility, but also the "associated project works, including dams and other impoundments that are part of the conduit system" to which a small conduit hydroelectric facility is attached. This argument is irrelevant because this rule does not require licensing of any portion of a consumptive water supply system if the related small conduit hydroelectric facility is exempted.

D. *Application Requirements.* Regarding the application requirements, most of the commenters recommended making the exhibits less comprehensive. The Commission has responded to these recommendations by further streamlining the exhibit requirements to the extent practicable. The Commission feels that the exhibit requirements, as adopted in this rule, are the minimum necessary to support an informed decision by the Commission.

Among other things, the Commission has eliminated these requirements that were included in the rule as proposed:

(1) purposes for which the facility's electric power is generated;

(2) costs of constructing the facility; and

(3) mapping of associated transmission lines.

Not all of the commenters were in agreement with this streamlining. Regarding the environmental report, now designated as Exhibit E, the USDA and DOI stated that the rule should elicit additional information from the applicant. They stated that an application should include a statement that the facility will not affect any territory within the jurisdiction of the National Park Service. DOI further stated that the Heritage Conservation and Recreation Service may need to review the exemption applications and that sufficient detail should be required in the environmental report to make review meaningful.

USDA was concerned that no procedures are provided for processing an Environmental Impact Statement (EIS) if a facility is determined to be a major Federal action significantly affecting the quality of the human environment. DOI further suggested that the applicant be made aware of the Reclamation Project Act of 1939, because there may be obligations imposed on the applicant by that statute.

Even though the exhibits, including the environmental report, have been streamlined, the Commission believes that, as set forth in the final rule, they will provide the Commission staff and interested agencies with sufficient information to ascertain the facility's impacts, the appropriateness of an exemption, and the desirable conditions of exemption. If granting an exemption in a particular instance would be a major Federal action significantly affecting the quality of the human environment, an EIS would be prepared in accordance with the Commission's rules implementing the National Environmental Policy Act. [6]

The Commission encourages the applicants to consult with both Federal and State agencies when preparing the application. The Commission will not undertake, however, to shoulder the burden of advising every applicant of its obligations under various other Federal laws that might affect a particular project.

ACWA commented on a requirement of proposed Exhibit A that the applicant identify "sources of the water supply for the related conduit" (§ 4.66(b)(2)(ii)). ACWA suggested that the word "direct" be added to modify "sources," to give the applicant guidance for tracing the source waters from the conduit. The Commission has decided to adopt, with modification, ACWA's suggestion. The change can be found in Exhibit A (§ 4.92(c)(3)(ii)). The pertinent phrase now reads "the *proximate natural* sources of water that supply the related conduit" [emphasis added], to indicate that the applicant need not trace beyond the nearest natural water source in any supply route.

E. *Application Procedures.* Central Power and Metropolitan suggested that the application procedures enabling automatic conversion from an application for exemption to an application for a license, if an exemption is denied, should be replaced with procedures for requesting such conversion. The Commission agrees with that suggestion and has changed the rule accordingly. Under the final rule, the applicant must notify the Commission of its intention to apply for a license before the application would be converted.

ACWA commented that the application procedures should include a provision that the Commission notify the applicant when the application is accepted for filing. This suggestion was already embodied in the proposed rule. When the application is determined to be complete, the Commission will notify the applicant in accordance with

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[6] The Commission will issue its final revised NEPA regulations in the near future. New NEPA regulations were proposed in 1979 in Docket No. RM79-69 (44 FR 50052, August 27, 1979). The NEPA regulations in §§ 2.80–2.82 will be used until the revised regulations are effective.

§ 4.31(c)(1) that the application has been accepted for filing.

F. *Terms and Conditions.* Terms and conditions of the proposed rule were addressed by a majority of the commenters, who made varied recommendations.

Proposed Article 1, which would have retained continuing health and safety authority in the Commission, was criticized by Metropolitan, ACWA, and CERCDC as imposing a condition which bears likeness to a statutory condition of licenses. The Commission has previously announced its intention to eliminate that article.[7] The other articles were renumbered accordingly.

Proposed Article 2, now Article 1, drew comments from Metropolitan, ACWA, and CERCDC expressing the view that the Commission had only one remedy for a violation of a term or condition—revocation. The Commission disagrees with their draconian approach. Article 1 of the final rule sets forth several remedies, in addition to revocation, available to the Commission when an exempt facility is found in violation of the terms and conditions.

PASNY and CERCDC suggested rewording proposed Article 3 to require that the exempt facility comply with the requirements that fish and wildlife agencies have determined at the time an exemption is granted are appropriate to carry out the purposes of the Fish and Wildlife Coordination Act, and not requirements that fish and wildlife agencies subsequently decide are appropriate. Article 3, now Article 2, has been revised slightly to clarify that intent. If any fish and wildlife agency believes that a particular small conduit hydroelectric facility should be subject to an "open-ended" condition permitting imposition of fish or wildlife protection measures after exemption, it may require that that provision be made a condition of the exemption.

III. Section-by-Section Analysis

The exemption procedures for small conduit hydroelectric facilities are contained in §§ 4.90 through 4.94 of the Commission's regulations rather than §§ 4.66 and 4.67 as originally proposed.

§ *4.90 Applicability and purpose.*

Section 4.90 briefly explains that the purpose of §§ 4.90–4.94 is to implement section 213 of PURPA. That section amends Part I of the Federal Power Act by establishing a new section 30 that provides that the Commission may exempt any small conduit hydroelectric facility from all or part of Part I of the Act.

§ *4.91 Definitions.*

Section 4.91 provides definitions pertinent to an understanding of the following sections. Paragraph (f) is particularly significant as it defines "small conduit hydroelectric facility" by elaborating and clarifying the pertinent limitations and terms set out in section 30 of the Act. This section also defines "conduit," "construction of a dam," "fish and wildlife agencies," and "non-Federal lands."

§ *4.92 Exemption applications.*

Paragraph (a) provides that any citizen or association of citizens of the United States, municipality, State, corporation incorporated under the laws of the United States or a State, may apply for exemption of an eligible facility. Paragraph (b) states that an exemption application must conform to requirements set forth in §§ 1.5 and 1.14 through 1.17 of this chapter and sets forth several specific rules for filing an application.

Paragraph (c) sets forth the required format and contents of the application, comprising an Introductory Statement and Exhibits A, B, E, and G. For a facility that does not meet the water discharge requirement in § 4.91(f)(5), the Introductory Statement must state that the application is accompanied by a petition for waiver of paragraph (f)(5) under § 1.7(b) of the Commission's regulations. The application will not be accepted for filing and processed until a petition for waiver is granted. If the petition is granted, the application is accepted for filing and is considered in accordance with the procedures of this rule.

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[7] *Metropolitan Water District of Southern California,* Project No. 2898, Order Approving Application for Exemption from Licensing (issued August 16, 1979).

Note that former Exhibits A and B have been interchanged and redesigned to provide a more logical format for the application, *i.e.*, introductory statement, project description, general location map, environmental report, and drawings. Exhibit C, drawings, is now designated Exhibit G.

Exhibit A must include a description of the facility and proposed mode of operation. Exhibit B is a general location map.

Exhibit E is an environmental report, similar to that required for minor projects. Exhibit E requires that the applicant also provide any determination which the applicant has obtained from the U.S. Fish and Wildlife Service, the National Marine Fisheries Service (in instances where anadromous fish may be involved), and any State agency regulating fish or wildlife resources, and other information considered relevant by the applicant.

Exhibit G must contain drawings showing structures and equipment.

The Commission re-emphasizes that this final rule does not impose any additional filing requirements. Instead, it requires less information, in a simpler form, than would be required for the license applications that would otherwise have to be filed.

§ 4.93 Action on exemption applications.

This section describes procedural actions the Commission will take on an application for exemption and certain measures that may be necessary, such as setting an application for hearing. The Commission must act within 90 days or the application is deemed approved, unless the Commission suspends the 90-day period. In paragraph (f), the Commission reserves the right to impose conditions in addition to the standard ones set forth in § 4.94, to protect water supply for consumption, the environment, public safety, and the water power resources of the region.

Paragraph (g) provides for conversion of any exemption application that is denied into a license application. The applicant must supply any additional information required for a license application.

§ 4.94 Standard terms and conditions of exemption.

Section 4.94 describes the standard terms and conditions for all exemptions, including the Commission's rights of investigation and enforcement and compliance with those terms and conditions determined by State and Federal fish and wildlife agencies.

(Federal Power Act, 16 U.S.C. §§ 792–828c; Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §§ 2601–2645; Department of Energy Organization Act, 42 U.S.C. §§ 7101–7352; E.O. 12009, 3 CFR 142 (1978))

IV. Effective Date and Applicability to Pending Applications

These rules have been promulgated under the Federal Power Act, as amended by PURPA, and, therefore, a right to rehearing exists under section 313 of the Federal Power Act.

In consideration of the foregoing, Part 4, Subchapter B, Chapter 1 of Title 18, Code of Federal Regulations, is amended as set forth below, effective May 19, 1980.

Any applications for exemption for which notice of acceptance for filing was given prior to the effective date of this rule are subject to the 90 day automatic exemption provisions in § 4.93 as of the effective date of this rule.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,147]

45 F. R. 28092 (April 28, 1980)

18 CFR Parts 154, 270, 271, 272, 273, and 274

[Docket No. RM79-44; Order No. 78]

Final Rule Defining and Deregulating Certain High-Cost Gas

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts final regulations defining and deregulating certain high-cost gas. As of November 1, 1979, section 121 of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3331) eliminates price controls for the first sale of gas for which a final determination has been obtained that the gas is high-cost natural gas described in section 107(c)(1) through (4) (15 U.S.C. 3317). The categories of gas which were deregulated include deep, high-cost natural gas, gas produced from geopressured brine, occluded natural gas produced from coal seams, and gas produced from Devonian shale. These final regulations substantially amend the interim regulation which were issued on October 24, 1979 (44 FR 61950, October 29, 1979).

EFFECTIVE DATE: The amendments contained in this rule, except for the provisions of §§ 272.103, 272.105 and 274.205, are effective April 22, 1980.

The amendments to § 272.103 (relating to the definitions) shall become effective April 22, 1980 with regard to jurisdictional agency determinations which have not yet become final under § 275.202 as of April 21, 1980.

The amendments to § 274.205 (relating to the filing requirements) shall become effective April 22, 1980 with respect to all applications for which a jurisdictional agency has not yet made a determination, as described under § 274.102, or has made a negative determination that has not become final as of April 21, 1980.

Section 272.105, which provides for separate billing, shall become effective May 28, 1980.

FOR FURTHER INFORMATION CONTACT:
NGPA Hotline, Office of Pipeline and Producer Regulation, 825 North Capitol Street, N.E., Washington, D.C. 20426, Toll Free (800) 424-5200, (202) 357-8137.

Issued: April 22, 1980.

I. Introduction and Summary

As of the effective date of the incremental pricing rule required under section 201 (15 U.S.C. § 3341), section 121 of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. § 3331) eliminates price controls for the first sale of gas for which a final determination has been obtained that the gas is high-cost natural gas described in section 107(c)(1) through (4) (15 U.S.C. § 3317). That date occurred November 1, 1979. The categories of gas which were deregulated include deep, high-cost natural gas (defined in section 107 of the NGPA), gas produced from geopressured brine, occluded natural gas produced from coal seams, and gas produced from Devonian shale.

The final regulations contained in this order modify the interim regulations on deregulated gas. They make minor modification in the definition of "natural gas produced from geopressured brine," substantially change the definition of "natural gas produced from Devonian shale" to include certain gas produced from sand stringers in the Devonian shales, permit the interim collection of the maximum lawful price permitted under section 102, permit retroactive collection, and require the seller to separately bill all sales of deregulated high-cost gas. The filing requirements have also been amended.

II. Background

The interim rules were issued on October 24, 1979, (44 FR 61950, October 29, 1979) effective as of November 1, 1979. Further comments were invited.

Especially solicited were comments concerning the provisions providing for charges and collections pending final determination that the gas qualifies as deregulated gas (interim collection); retroactive collection of the contract price after the final determination is obtained; and proper ways to treat first sales among affiliated entities and sales by pipelines which do not qualify as first sales.

Written comments were due by November 19, 1979, and a public hearing was held on December 4, 1979. Copies of comments and a transcript of the public hearing may be found in the public files in Docket No. RM79-44.

III. Analysis of Comments

A. Definitions and Filing Requirements

1. *Natural gas produced from geopressured brine.* The interim rule provided the following definition of gas produced from geopressured brine:

> § 272.101(a) *"Natural gas produced from geopressured brine"* means natural gas dissolved before initial production of natural gas in subsurface brine aquifers with at least 10,000 parts of Sodium Chloride per million parts of water and an initial reservoir geopressure gradient in excess of 0.465 pounds per square inch for each vertical foot of depth.

Few comments were received on the definition of gas produced from geopressured brine. One comment suggested that the required salinity of the brine should decrease in deeper reservoirs since deep gas is more expensive to produce. Another commenter argued that deregulation will not create incentives for the development of gas dissolved in brine unless free gas produced in association with the brine is also deregulated. Finally, some commenters pointed out that salts and solids other than Sodium Chloride may be dissolved in brine and therefore the definition of brine should not be determined solely by the amount of Sodium Chloride dissolved in the aquifer.

Because brine is often composed of other dissolved salts and solids the final definition of brine has been modified to include all dissolved solids and is no longer limited to Sodium Chloride. The other suggestions have not been adopted.

Qualification will not depend upon the depth of the reservoir since, by statutory direction, qualification under this category of gas relates *only* to whether the gas is dissolved gas produced from geopressured brine. Furthermore, the final definition is not so restrictive that it will exclude the deeper brine aquifers.

In the interim regulations the Commission considered the possibility of qualifying "free gas" caps found in association with brine. For the same reasons elucidated therein, the Commission will not include such free gas in its definition of "natural gas produced from geopressured brine."

2. *Natural gas produced from Devonian shale.* The interim rule defined "gas produced from Devonian shale" as follows:

> § 272.101(c) *"Natural gas produced from Devonian shale"* means natural gas produced from the fractures, micropores and bedding planes of shales deposited during the Paleozoic Devonian Period.

The preamble stated that the rule was not intended to deregulate gas produced from "stringers" (potentially gas-producing rock within the Devonian shale strata). Under the interim rule, if such gas and deregulated gas were produced from a single well, pricing for gas from the well was to be based on a reasonable allocation of production from the different pricing categories.

Comments voiced opposition to the exclusion of stringer production from qualification as gas produced from Devonian shale. Some stated that an accurate allocation is impractical in the case of open hole completions. None made any suggestion as to how the definitions could be formulated to include only production from currently uneconomical gas-bearing Devonian shale. Additionally, comments pointed out that it would not be feasible to obtain a gamma ray log for some old wells.

Our review of shale production and resource potential indicates that the definition needs to be changed. The interim rule's definition was extremely restrictive. It precluded qualification of gas produced from formations which contain too much shale to be considered anything other than shale for purposes of completion practices, but contain enough quartz or other coarser material to be designated stringers of other rock. Also, since a large number of wells produce in part from such stringers, production from a large number of wells would have required allocation. Such a requirement would have been unduly burdensome given the characteristics of most Devonian shales.

Input from industry, staff, and the various affected jurisdictional agencies has led to the following conclusions: Shales characteristically emit a higher level of natural gamma radiation than the coarser materials in the stringers because of larger quantities of radioactive isotopes of potassium, thorium and uranium. The change in lithology from shale to some other associated sedimentary rock is gradual and seldom total, but stringers containing a lower percentage volume of shale generally have reduced natural gamma ray emission activities. The natural gamma ray emission can be recorded on a gamma ray log and the percentage volume of shale at any point can be roughly estimated from that log.

One commenter suggested using a "gamma ray index" (GR index) to calculate the percentage of shale by the following formula:

$$\text{GR index} = \frac{\text{Gamma Ray log—Gamma Ray clean sand}}{\text{Gamma Ray shale—Gamma Ray clean sand}}$$

While providing a reasonable estimate, this method would require that a clean sand of the same depositional age be encountered by the well bore. This is an unusual occurrence. Since the industry generally accepts an interval composed of 60 to 70 percent shale as one requiring treatment as shale for purposes of permeability calculations, potential estimates, and completion techniques, the suggested method has been simplified to calculate a GR index as follows:

$$\text{GR index} = \frac{\text{Gamma Ray log}}{\text{Gamma Ray shale}}$$

While this is not a rigorous method, it does provide an estimate of the shale volume. The Commission has adopted this as an appropriate method for estimating shale content and considers natural gas from any Devonian age interval to be produced from Devonian shale if less than 5 percent of the gross Devonian age interval penetrated by the well bore has a GR index of less than 0.7.

A gamma ray log is required from all wells drilled after October 31, 1979, for which a section 107(c)(4) determination is sought. The gamma ray log filing requirement contained in the interim rule has been amended to require that the shale base line and a line identifying 70 percent of the shale base line (GR index of 0.7) be superimposed over the Devonian section of the log.

If a gamma ray log is not available or cannot be reasonably obtained in wells drilled prior to November 1, 1979, a driller's log or a similar report which indicates the general characteristics and depths of the strata penetrated in the Devonian age depositions may be filed. In addition, the reporting requirements have been amended to require that the applicant demonstrate that the percent footage of the potentially disqualifying stringers does not exceed 5 percent of the gross Devonian age interval penetrated by the well bore.

3. *Occluded natural gas produced from coal seams.* The interim rule defined "occluded natural gas produced from coal seams" as follows:

> § 272.101(b) *"Occluded natural gas produced from coal seams"* means naturally occurring natural gas released from entrapment from the fractures, pores and bedding planes of coal seams.

Again, this definition was written to disqualify stringers and require allocation of production between the coal seams and the stringers. For the same reasons discussed with respect to gas produced from Devonian shale, commenters objected to such a restrictive definition.

The Commission notes that coal is different from shale in that coal usually exists in distinct beds. It is easily distinguishable from other surrounding rock because there is a distinct lithologic change at the interface between the coal and the other surrounding rock. Moreover, the use of the term "occluded" in section 107(c)(3) of the NGPA indicates that the gas must be trapped in the coal seam to qualify. While allocation will be difficult, it is necessary to enforce applicable maximum lawful prices. Therefore, the Commission has decided to retain the interim rule's definition of coal seam gas as excluding stringers.

Additionally, one commenter pointed out that the filing requirements did not accommodate the special techniques used to remove gas from gaseous coal before mining the coal. Such techniques do not involve the drilling of wells. Instead, several "longholes" are drilled horizontally from larger shafts in the coal seam. The gas migrates from the coal to the longholes, to the larger shafts, and eventually to the surface through a vertical shaft. The process was developed to ensure mine safety in gaseous coal mines, but the gas can be collected and processed for marketing. The filing requirements have been amended to permit alternate filing requirements where the method of extracting the coal gas differs from the usual gas well, for example, as when longholes are drilled prior to mining the coal.

B. Interim and Retroactive Collections

Under the interim rule, the price for gas was deregulated only when the jurisdictional agency eligibility determination became final. Pending final determination, the gas continued to be subject to otherwise applicable maximum lawful prices. (Interim collection at the section 102 maximum lawful price was proposed for consideration and comment.) Once the determination became final, the parties to the sale could make retroactive price adjustments for deliveries which took place between November 1, 1979, or the date the application was filed, if later, and the time the determination became final if their contracts specifically permitted collection of such adjustments on a retroactive basis.

The commenters objected to the retroactive and interim collection provisions as well as the proposed interim collection provisions. Their objections were based on several arguments. First, they argued that the Commission's authority over gas described at section 107(c) (1) through (4) ceased as of November 1, 1979, and therefore the Commission cannot require that a final determination be obtained before removing price controls. Second, they argued that since section 503 of the NGPA (15 U.S.C. 3413) directs the Commission to provide for interim collection of the maximum lawful price for which application is made, the price of deregulated gas should also be decontrolled during the period for interim collection.

Third, commenters argued that the interim collection provision will have a significant, adverse impact on producers since they could delay the receipt of needed revenues for several months. They claimed that the retroactive collection provision also did not satisfy producers' cash flow requirements during the interim. Some of the commenters claimed that the impact on producers would be significant enough to cause producers to delay production until the determination became final, whereas the impact on the consumer of permitting interim collection of deregulated prices would be insignificant. A few of the commenters suggested that, at least, deep, high-cost gas should be allowed the deregulated price under interim collection since it is easy to determine whether gas qualifies as deep, high-cost gas, and there is little risk that such an application would be denied.

Finally, commenters argued that the interim collection provisions require the filing of unnecessary applications. Since the interim collection provisions allowed only the interim collection of the otherwise applicable maximum lawful price, many applicants needed to submit applications for deregulation and for the otherwise applicable maximum lawful price.

The Commission does not agree that section 121 eliminates the Commission's duty to control the price paid for gas for which a final determination that the gas qualifies as deregulated high-cost gas has not been obtained. Section 121(b) eliminates price controls only with respect to "the first sale of high-cost natural gas"[1] described in section 107(c) (1) through (4). Section 107(c) defines high-cost natural gas so as to include only gas which has been "determined in accordance with section 503" to be within one of the listed categories.[2] Hence gas is not high-cost gas, and is not deregulated, until a final determination has been obtained.

The Commission also disagrees with the comment that we should provide for interim collection of the deregulated price. Section 503(e)(2)(A) (15 U.S.C. 3413(e)(2)(A)),[3] which sets out the general authority of the Commission to provide for interim collections, permits interim collection of the maximum lawful price for which application is made. Section 121(b) provides that the maximum lawful price provisions of the NGPA cease to apply to first sales of high-cost gas described in section 107(c) (1) through (4). From a strict literal reading of these sections, it would appear that interim collection of deregulated prices is not permitted. This is so because section 503(e)(2) permits interim collection of the applied for *maximum lawful price*, whereas under section 121(b) the applied for section 107(c) (1) through (4) price is a deregulated price, not a maximum lawful price. Such was the Commission's tentative conclusion in promulgating the interim rules. Upon reconsideration of the issue the Commission no longer believes that section 503(e) was intended to preclude the Commission from permitting any method or means of providing for interim collection of some price other than an otherwise applicable maximum lawful price. This position is supported by the language of section 503(e)(2)(A) which authorizes the Commission to provide a method or methods whereby a seller may make interim charges and collections of the maximum lawful price "for which a petition is filed for a determination under this section in any case in which such price exceeds the appropriate maximum lawful price under section 109." Section 503(a)(1)(D) requires the filing of such petitions for determinations under section 107(c).

Presumably, Congress intended to allow interim collections whenever petitions for determinations are required by the NGPA in recognition of the delay resulting from the determination process in collecting the higher revenues generated from these first sales. There is no evidence that Congress specifically intended to single out section 107(c)(1) through (4) gas or to inhibit the exploration and development of high-cost natural gas reserves by creating a cash-flow problem which would not exist for any other category of natural gas for which a petition for determination must be filed under the NGPA. Indeed, it would have been anomalous for Congress to have provided for interim collections for all of the incentive prices except section 107 when Congress has specifically recognized the extraordinary economic risks and costs accompanying production of section 107 gas.

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[1] Section 121(b) (15 U.S.C. 3331(b)) provides:

(b) High-Cost Natural Gas—Effective beginning on the effective date of the incremental pricing rule required under section 201, the provisions of subtitle A respecting the maximum lawful price for the first sale of natural gas shall cease to apply to the first sale of high-cost natural gas which is described in section 107(c) (1), (2), (3), or (4).

[2] Section 107(c) provides:

(c) Definition of High-Cost Natural Gas—For purposes of this section, the term "high-cost natural gas" means natural gas determined in accordance with section 503 to be—

(1) produced from any well the surface drilling of which began on or after February 19, 1977, if such production is from a completion location which is located at a depth of more than 15,000 feet;

(2) produced from geopressured brine;

(3) occluded natural gas produced from coal seams;

(4) produced from Devonian shale; and

(5) produced under such other conditions as the Commission determines to present extraordinary risks or costs.

[3] Section 503(e)(2)(A) provides:

(2) Alternate Interim Collection Authority.

(A) General Rule—Promptly after the date of the enactment of this Act, the Commission shall, by rule or order, provide one or more methods under which a seller of natural gas may, in accordance with requirements established, for such period as may be prescribed, under such rule or order, charge and collect for any first sale of such natural gas the maximum lawful price under title I for which a petition is filed for a determination under this section in any case in which such price exceeds the appropriate maximum lawful price under section 109.

Having concluded that Congress did not intend to exclude section 107 gas from interim collection treatment, the Commission may, pursuant to its general rulemaking authority found in section 501(a) of the NGPA, fill in the gap left by Congress and establish interim collection procedures for section 107 gas.

There remains the question of what interim collection price should be established for section 107 gas. This problem is unique to section 107(c) (1) through (4) because such gas is deregulated, whereas other categories of gas eligible for interim collection are subject to the maximum price limitations found in subtitle A of the NGPA. Neither the statute nor the legislative history provide much guidance. However, section 501 gives the Commission authority in circumstances such as are presented here to fill in the interstices of the statute so long as this is done in a manner consistent with the overall statutory scheme of the NGPA.

The commenters argued that interim collection of a deregulated rate is necessary to guarantee commencement of production immediately after applications are filed and insisted that such a rate would have an insignificant impact upon consumers. The Commission does not accept these arguments and for the reasons discussed below has limited the price that may be collected during interim collection to the maximum lawful price specified in section 102 of the NGPA (relating to new natural gas and certain OCS gas).

The section 102 maximum lawful price is being adopted for interim collection in the final rule because that was the price adopted by Congress with respect to deep, high-cost gas prior to the date of deregulation.[4] That price was applicable for approximately a year and was deemed adequate by Congress to encourage development of deep, high-cost gas during that year. Furthermore, the section 102 price represents the price which Congress found was necessary and adequate to provide an incentive for the development of new reserves of gas. Since retroactive collection of the deregulated price is permitted back to the date application was made, and in most cases the interim period between the date of filing an application and the date on which a determination becomes final have been shortened to a few months, interim collections of the section 102 price should be of minimal disadvantage to producers and at the same time should provide protection to purchasers in cases where the determinations are eventually negative. Although, as commenters suggested, the ultimate consumer of gas may not feel any significant impact of paying deregulated rates on an interim basis, such a provision would place first sale purchasers in jeopardy of paying deregulated prices for gas which is eventually determined not to qualify for deregulation. Although the amounts collected in such a case would be subject to refund, large amounts of money could be collected during the interim collection period and producers would have little incentive to pursue timely determinations. On balance, the Commission believes that limiting the price that may be collected during interim collections will limit the amount of money collected subject to refund without seriously disadvantaging producers. The retroactive collection provisions permit eventual full recovery of the deregulated price.

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[4] This category of gas was deregulated along with section 107(c) (2) through (4) on November 1, 1979.

Finally, the adoption of a rule permitting interim collection of the section 102 price (as opposed to a prohibition of interim collections for deregulated gas) obviates the necessity of producers filing applications for determinations under more than one section of the NGPA in order to make interim collections for deregulated gas.

With respect to the retroactive collection provisions, the commenters objected to the provision that the contract must specifically permit retroactive collection. They claimed that producers had relied on the Commission's decisions in Order No. 23 (44 FR 16895, March 20, 1979) to leave questions regarding sales contract interpretations to the parties to the contract. They argued that, based on that decision, many contracts do not specifically provide for retroactive collection. Commenters also pointed out that since the interim rule was issued only eight days before it was to become effective, even producers anticipating deregulation could not have prepared and filed determination applications in time to permit retroactive collections to November 1, 1979. They suggested that the Commission extend the period in which producers can file applications and collect retroactively for deliveries which have taken place since November 1, 1979.

The retroactive collection provisions regarding deregulated gas have been incorporated in and conformed to the retroactive collection provisions applicable to gas subject to maximum lawful prices in § 273.204. Since Order No. 23 adopted a policy favoring interpretation by the parties to the contract, the same policy will be applied with respect to deregulated gas. However retroactive payment may occur only with respect to deliveries made since the later of November 1, 1979, or the date the application is filed for a determination that the gas qualifies as deregulated gas, except that if an application for determination was filed on or before [60 days from the effective date of this rule], retroactive collection may be computed, charged and collected for first sales of deregulated natural gas delivered on or after November 1, 1979. The period between November 1, 1979, and [60 days from the effective date of this rule] is provided because the filing requirements in the interim rule were not published in time to permit parties to prepare and submit applications by the effective date of the rule, and this rule changes the definition of some of the gas deregulated as of November 1, 1979.

C. Separate Pricing of Regulated and Deregulated Gas

Section 272.102(c) of the interim rule provided that:

> (c) *Circumvention of maximum lawful prices.* No portion of the price paid for natural gas which qualifies under one of the categories of natural gas defined in § 272.102 may represent consideration for natural gas which is subject to a maximum lawful price under Part 271.

At page 11 of the mimeo (44 FR 61952) the preamble to the interim rule stated that the rule was intended to require "'unbundling' of gas sales transactions so that regulated and unregulated transactions are separately priced." Commenters claimed that the intent of the rule at § 272.102(c) was unclearly explained and implied, without so stating in the rule, that the price for decontrolled gas should be covered by a separate contract. They argued that separate contracts should not be required since the practice in the industry has been to include all gas from identified productive acreage in one sales contract even though the gas may be subject to different maximum lawful prices.

The Commission is concerned that situations may arise where prices paid for deregulated gas may be paid as consideration for the sale of gas subject to price regulation. The Commission does not intend to limit or question prices paid for deregulated high-cost gas. At the same time, we do not intend to permit circumvention of applicable maximum lawful prices and would consider sales in which part of the price paid for deregulated high-cost gas was paid as compensation for the sale of price-regulated gas to be circumventing applicable maximum lawful prices. To permit the Commission to detect and deter circumvention of maximum lawful prices when price-regulated gas is sold in association with price-deregulated gas, the Commission has required that all first sales of deregulated high-cost gas be separatey billed. In addition all first sales of gas for which an application for a determination (that the gas qualifies as deregulated high-cost gas) has been filed but is still pending, must also be separately billed along with sales of gas which has been finally determined to be deregulated gas.

D. Pipeline and Affiliate Production

In the preamble to the interim rule the Commission requested comments on the proper way to treat pass-through in purchased gas adjustment clauses of the first sale acquisition costs of an interstate pipeline affiliate's production of deregulated gas.

We also requested comments on whether pipeline or affiliate production qualifying under section 107(c) (1) through (4) should qualify for the deregulated price if sold in a sale other than a first sale.

1. *Affiliate production.* As commenters noted, under § 270.203(c)[5] a sale by an affiliate of a pipeline or distributor qualifies as a first sale if such affiliate is not itself a pipeline or distributor and the Commission has not determined, on application, not to treat such sale as a first sale. Section 601(b)(1)(A) of the NGPA (15 U.S.C. 3431(b)(1)(A)) provides that any amount paid in a first sale for the purchase of deregulated gas shall be deemed just and reasonable. Section 601(c)(2) (15 U.S.C. 3431(c)(2)) guarantees that an interstate pipeline may pass through such an amount unless the amount paid was excessive due to fraud or abuse. However, with respect to first sale purchases from an affiliate the pipeline may recover no more than "the amount paid in comparable first sales between persons not affiliated with such interstate pipeline." (Section 601(b)(1)(E), 15 U.S.C. 3431(b)(1)(E).)

To ensure that the Commission will be able to determine whether the purchased gas acquisition costs for affiliate production do not exceed the amount paid in comparable first sales between non-affiliated entities, we have amended § 154.38(d)(4)(ii) to require pipelines to designate purchases of deregulated high-cost gas from affiliated entities in their schedules of gas costs filed with the Commission. This burden is minimal and will permit the Commission to identify sales between affiliated entities and compare such prices with prices paid between non-affiliated entities.

2. *Non-first sale price for pipeline production.* Under § 270.203 (a) and (b) a sale of gas by a pipeline or distributor is not a first sale unless the sale is comprised exclusively of production by the pipeline or distributor or the sale is a mixed volume sale which would not be regulated pursuant to the Natural Gas Act (15 U.S.C. §§ 717–717w) or by a State agency empowered by State statute to establish, modify, or set aside the rate for such sale. Consequently very few sales of pipeline production qualify as first sales. Section 121 removes price controls only with respect to first sales.

In Docket No. RM80–6,[6] the Commission proposed a substantive rule in § 2.66a to extend (with exceptions pertaining to gas subject to cost of service rate treatment) NGPA maximum lawful prices to sales by pipelines and distributors which would not qualify as first sales. At this time no rule has been issued in Docket No. RM80–6. The question raised in the preamble to the interim deregulation rules regarding the price applicable to non-first sales of gas qualifying for deregulation was not addressed in the proposed rule in Docket No. RM80-6.

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[5] *See* Order No. 58 (44 FR 66577, November 20, 1979).

[6] *See* Notice of Proposed Rulemaking, 44 FR 66613, November 20, 1979.

In answer to the inquiry in this docket, commenters insisted that the Commission has and should continue to permit pipeline producers to obtain the same price for gas that independent producers obtain. They argued that the NGPA does not indicate that pipeline producers should be treated differently than independent producers. A few suggested that the Commission could impose a limitation on the non-first sale price for deregulated gas similar to that imposed on first sales between affiliated entities.

Others argued that the suggestion that a pipeline's passthrough of its own production could be subjected to a ceiling price was not consistent with statements made in the notice of proposed rulemaking in Docket No. RM80-6.

We agree with the recommendation of one commenter that decisions regarding sales of pipeline production that are not first sales should be made in the context of Docket No. RM80-6. All comments submitted in response to this rulemaking which addressed the issue of the price for non-first sales of pipeline production qualifying as deregulated gas will be considered in formulating the rule in Docket No. RM80-6.

III. Summary of Amendments

This rule adds a new § 270.207 to Subpart B of Part 270 precluding circumvention of ceiling prices where the price paid for deregulated high-cost gas represents consideration for the sale of natural gas not deregulated under Part 272. In connection with this requirement, separate billing has been required under § 272.105 for all deregulated high-cost gas and for all gas for which an application for a determination that the gas qualifies as deregulated high-cost gas has been filed, and is pending.

References to deep, high-cost gas have been moved to Part 372 from Subpart G of Part 271, which now relates to ceiling prices for gas established by the Commission as high-cost gas under section 107(c)(5).

The definition in Part 272 of "natural gas produced from geopressured brine" is substantially the same as in the interim rule, except that the dissolved solids need not consist of Sodium Chloride. The definition of "gas produced from Devonian shale" has been amended to include gas produced from Devonian age intervals if no less than 95 percent of the gross Devonian age interval penetrated by the well bore has a GR index of 0.7 or more.

Various sections in Part 273, relating to interim and retroactive collection, have been amended to permit interim collection of the section 102 maximum lawful price and retroactive collection of the deregulated price.

The filing requirements for gas produced from Devonian shale have been amended to require a gamma ray log with super-imposed indications of the shale base line and a line representing a GR index of 0.7. The filing requirements also require the applicant to demonstrate that the percentage of the interval with a GR index of less than 0.7 is no greater than 5 percent of the gross Devonian interval.

The filing requirements for occluded natural gas produced from coal seams have been amended to accommodate various methods of producing the gas.

V. Effective Dates

The amendments contained in this rule, except for the provisions of §§ 272.103, 272.105 and 274.205, shall become effective immediately (April 22, 1980). The amendments to § 272.103 (concerning definitions) shall become effective immediately (April 22, 1980) with regard to jurisdictional agency determinations which have not yet become final under § 275.202 as of the day before the day of issuance of this rule (April 21, 1980). The amendments to § 274.205 (concerning the filing requirements) shall become effective immediately (April 22, 1980) with respect to all applications for which a jurisdictional agency has not yet made a determination, as described under § 274.102, or has made a negative determination that has not become final, as of the day before the date of issuance of this rule (April 21, 1980). In the case of negative determinations already received by the Commission for which the 45 day period under § 272.202(a) has not expired (or if applicable, the 120 day period under § 275.202(e)), we shall provide applicants the opportunity to supplement their applications in accordance with the amended regulations. In such cases we will remand the determinations to the jurisdictional agencies for their reconsideration. Section 272.105, requiring separate billing, shall become effective 30 days from the date of publication of this rule in the Federal Register (May 28, 1980) with respect to all monthly billing periods that begin on or after 30 days from the date of publication of this rule.

Good cause exists to make the definitions, and interim and retroactive provisions effective immediately (April 22, 1980) because the amendments relieve previous restrictions. The other amendments, except for § 272.105, which is effective 30 days from the date of publication of this rule in the Federal Register (May 28, 1980), are technical and conforming amendments and shall also be made effective immediately (April 22, 1980).

(Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301–3432; Natural Gas Act as amended, 15 U.S.C. to § 712–717)

In consideration of the foregoing, Parts 154, 270, 271, 272, 273 and 274 of Chapter I, Title 18, Code of Federal Regulations, are amended, as set forth below, effective as set forth above. These amendments are issued as final regulations, except for §§ 271.701 and 273.204(a)(1)(ii), which will remain as interim rules until further notice.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,148]

45 F. R. 29011 (May 1, 1980)

18 CFR Part 154

[Docket No. RM79-23; Order No. 10-C]

Interstate Pipeline Recovery of State of Louisiana First Use Tax

April 24, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: This final rule amends the procedures, established in Order No. 10 (43 FR 45553, October 3, 1978), No. 10–A (43 FR 60438, December 28, 1978) and No. 10–B (44 FR 13460, March 12, 1979) for recovery of the Louisiana First Use Tax by interstate natural gas pipelines. The rule sets forth the rate treatment and accounting procedures to be followed until a final and non-appealable court determination of the constitutionality of the Louisiana First Use Tax is made.

EFFECTIVE DATE: This final rule is effective as of April 24, 1980.

FOR FURTHER INFORMATION CONTACT: William A. Topping, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426. Phone: 202–357–8583.

The Commission has under consideration applications for rehearing of the March 30, 1979, order in *Arkansas-Louisiana Gas Company, et al.*, Docket Nos. RP79-53, *et al.*[1] After reviewing these applications, we concluded that Order No. 10–B as well as the March 30 Order should be modified. The United States Court of Appeals for the Fifth Circuit has granted our request for a remand of the record in *Tennessee Gas Pipeline Company, et al. v. Federal Energy Regulatory*

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[1] See pages 6–8, *infra*, for a discussion of the proceedings in those dockets and this docket.

Commission, No. 78–3816, so that we may modify Order No. 10–B.[2] Accordingly, we will modify Order No. 10–B, but we turn first to the events which lead to Order No. 10–B and the March 30 Order.

I. Louisiana First Use Tax on Natural Gas.

In July of 1978, the State of Louisiana adopted a law establishing the First Use Tax on Natural Gas.[3] The First Use Tax is imposed, at a rate of 7 cents per thousand cubic feet ("Mcf"),[4] upon the first "use"[5] of certain natural gas[6] within Louisiana.

The constitutionality of the First Use Tax has been questioned since the inception of the tax. In testimony before the Revenue and Fiscal Affairs Committee of the Louisiana Senate several witnesses questioned the constitutionality of the tax,[7] and the sponsors of the tax noted questions regarding its constitutionality.[8]

The Commission is of the opinion that the First Use Tax is unconstitutional and directly interferes with paramount federal authority to determine the terms and conditions on, and the rates at, which natural gas may be transported and/or sold in interstate commerce. Accordingly, it instituted proceedings challenging the First Use Tax, *FERC* v. *McNamara, et al.*, Civil Action No. 78–384 (M.D. La. filed September 29, 1978),[9] and has supported the states' motions for leave to file an original complaint in

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[2] By order filed October 12, 1978, the Fifth Circuit granted the Commission's motion and "remanded (the cause) to the Commission so that they may modify their orders."

[3] 1978 La. Sess. Law Serv. 452 (Act No. 294), codified as La. Rev. Stat. §§ 47:1301–47:1307 (West) (1979 Supp.) Hereinafter referred to as "First Use Tax." This act is one of several acts adopted to impose a tax on specified "uses" of certain classes of natural gas which is transported into and/or through Louisiana in interstate commerce to provide for credits against that tax liability, and to dispose of revenues generated by the First Use Tax. The other acts are: (1) Act No. 293, 1978 La. Sess. Law Serv. 480, codified as La. Rev. Stat. §§ 47:1351 (establishes a First Use Tax Trust Fund); (2) Act No. 436, 1978 La. Sess. Law Serv. 842, codified as La. Rev. Stat. § 47:647 (allows credits against liability for the Louisiana Severance Tax); (3) Act No. 599, 1978 La. Sess. Law Serv. 1112, to be codified as La. Rev. Stat. § 47:11 (allows credits against Louisiana state and local taxes for electric generating utilities, gas distribution companies, and industrial users of natural gas); and (4) Act No. 797, 1978 La. Sess. Law Serv. 1613 (places on ballot a proposal to amend Louisiana constitution to incorporate therein a First Use Tax Trust Fund).

[4] La. Rev. Stat. § 47:1303(B).

[5] The term "use" is defined broadly as "(1) the sale; (2) the transportation in (Louisiana) to the point of delivery at the inlet of any processing plant; (3) the transportation in (Louisiana) of unprocessed natural gas to the point of delivery at the inlet of any measurement or storage facility; (4) transfer of possession or relinquishment of control at a delivery point in (Louisiana); (5) processing for the extraction of liquefiable component products or waste materials; (6) use in manufacturing; (7) treatment; or (8) other ascertainable action at a point within (Louisiana)." La. Rev. Stat. § 47:1302(8).

[6] Natural gas is subject to the First Use Tax if it is not subject to any severance or production tax levied by Louisiana or any other state or territory of the United States or is not subject to any import tax or tariff levied by the United States on imports from foreign countries. La. Rev. Stat. § 47:1303(A). Because almost every state including Louisiana (La. Rev. Stat. §§ 47:631–47:646), imposes a severance or production tax on gas produced within the state, the First Use Tax will apply only to gas not subject to state taxation. Such gas is produced from federal enclaves within a state (*e.g., Mississippi River Fuel Corp.* v. *Cocreham*, 382 F.2d 929 (5th Cir. 1967)) or the federal portion of the Continental Shelf (43 U.S.C. § 1331(a)(2)), or is imported from a foreign country. While the First Use Tax is imposed on gas from all three sources, the principal target of the tax is gas from the federal portion of the Continental Shelf ("OSC gas") which enters Louisiana. *Hearings on H.B. 768 Before the Revenue and Fiscal Affairs Committee of the Louisana Senate*, 1 (Governor Edwards), 3 (Rep. Tauzin), 13 (Mr. Slaton) (Hereinafter *"Senate Hearings"*); *Hearings on H.B. 768 Before the Committee on Ways and Means of the Louisiana House of Representatives*, 7 (Rep. Tauzin) (Hearing of June 5, 1978) (Hereinafter *"House Hearings"*); *id.*, 8–9, 16 (Mr. Brooksher), 25–28 (Mr. Woodward) (Hearing of June 6, 1978).

[7] *Senate Hearings*, at 13–18 (Mr. Slaton), 18–22 (Mr. Gardner), 22–25 (Mr. Woodward).

[8] The Governor of Louisiana stated: "May I say first that no one and I repeat and emphasize no one can tell you whether the legislation is constitutional or is not constitutional," and Representative Tauzin, author of the First Use Tax, stated: "The reason that we do that (establishment of a trust fund) is the same as the governor said that it is possible and we have got to recognize it, that the courts could rule that we have some constitutional problem with our act." *Senate Hearings*, at 2, 6.

[9] By order filed January 26, 1979, the district court stayed proceedings in this case pending the outcome of the proceedings in *Edwards, et al.* v. *Transcontinental Gas Pipe Line Corp., et al.*, No. 216,867 (19th Judicial District Court, La., filed September 22, 1978). The Commission appealed this order, *FERC* v. *McNamara*, No. 79–1403 (5th Cir.), and the Fifth Circuit has indicated that these

Maryland, et al. v. *Louisiana,* No. 83 Original (U.S. filed March 29, 1979), and their motion for judgment on the pleadings.[10]

The cost of the First Use Tax to the interstate natural gas pipelines and their customers is significant; the first year liability alone will exceed $280 million. Until a court declares the First Use Tax unconstitutional, or until collection of the tax is enjoined, the interstate pipelines must pay the First Use Tax, since non-payment subjects the interstate pipelines to penalties and to forfeiture of the natural gas.[11] Considering these factors, the Commission established procedures for recovery of the First Use Tax, subject to refund, pending the conclusion of litigation challenging the constitutionality of that tax. These procedures balanced the needs of the interstate pipelines to recoup the amounts paid for the First Use Tax from gas consumers or other persons for whom they render services, with the Commission's responsibility to protect the ultimate consumers from a tax of questionable constitutionality. This order, although revising and simplifying those procedures, continues to balance equitably the interests of the pipelines and gas consumers.

II. Procedural History

A. Commission Orders

In Order Nos. 10, 10–A, and 10–B,[12] the Commission established procedures governing recovery of the First Use Tax.[13] These orders amended § 154.38 of the Commission's Regulations (18 CFR 154.38) by adding a new paragraph (h).

Paragraph (h), as amended by Order Nos. 10–A and 10–B, permits pipelines to collect the First Use Tax, subject to refund, pursuant to a temporary tracking mechanism similar to a purchased gas adjustment clause.

While allowing the pipelines to collect the First Use Tax from their gas customers, the Commission imposed conditions to ensure that gas consumers receive refunds of all amounts paid pursuant to § 154.38(h) with interest upon a final court determination that the First Use Tax is unconstitutional. In Order Nos. 10 and 10–A, the Commission required the pipelines to deposit all funds collected in an escrow account until a final court determination of the constitutionality of the First Use Tax. In Order No. 10–B, the Commission, acting in response to comments and petitions for rehearing, amended § 154.38(h) to allow pipelines to select either the escrow account procedure established in Order No. 10–A, or, under certain conditions, a corporate undertaking procedure.

Pursuant to Order Nos. 10, 10–A, and 10–B, eighteen pipeline companies filed tariff sheets to establish provisions for tracking and deferred accounting of the First Use Tax. By orders issued March

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proceedings should be stayed pending further developments in *Maryland, et al.* v. *Louisiana, infra.*

[10] By order entered June 18, 1979, the Supreme Court granted leave to file the original complaint, and directed Louisiana to answer the complaint within sixty (60) days. Louisiana has answered the complaint and moved for appointment of a special master. Maryland, *et al.*, have moved for judgment on pleadings requesting the Court to declare the tax unconstitutional, and have opposed the motion for appointment of a special master. In response Louisiana has filed a motion to dismiss and has opposed the motion for judgment on pleadings. Maryland, *et al.* have opposed the motion to dismiss. In addition, New Jersey has filed a complaint, and a brief in support thereof. Seventeen interstate pipelines have moved for leave to intervene and to file a complaint and have filed a motion for judgment on the pleadings and a brief in support thereof. Finally, Associated Gas Distributors have filed for leave to file a brief *amicus curiae* in support of the motion for judgment on the pleadings and the brief.

On March 3, 1980, the Supreme Court appointed John F. Davis as special master in *Maryland* v. *Louisiana.*

[11] La. Rev. Stat. § 47:1306(B).

[12] 43 FR 45553 (October 3, 1978); 43 FR 60436 (December 28, 1978); 44 FR 13460 (March 12, 1979), petitions for review pending *sub nom. Tennessee Gas Pipeline Co., et al.* v. *FERC,* No. 78-3816 (5th Cir.).

[13] In addition to establishing these procedures, the Commission challenged the constitutionality of the First Use Tax. See page 4 and notes 9 and 10, *supra.*

30, 1979,[14] and May 9, 1979,[15] the Commission accepted the original or revised tariff sheets of the eighteen pipelines. Subject to the refund provisions of Order No. 10–B, these pipelines are presently collecting, from their customers, funds to cover the pipelines' First Use Tax liability. Several pipelines filed applications for rehearing of the March 30 Order. After reviewing these petitions for rehearing, the Commission finds that the refund provisions of Order No. 10–B as applied in the Commission's March 30 Order should be amended. Thus, the Commission is amending Order No. 10–B and clarifying the March 30 Order.

B. Petitions for Rehearing of March 30 Order

Applications for rehearing of the Commission's March 30 Order have been filed by twelve pipelines.[16] The major issues raised in the applications for rehearing are: (1) Whether the Commission can require pipelines selecting the corporate undertaking to refund "voluntarily" those payments made on that portion of the First Use Tax found unconstitutional by a final and non-appealable court order; and (2) whether paragraph (N) of the March 30 Order denies pipeline companies their right to seek judicial review of the Commission's orders.

After reviewing these applications for rehearing, the Commission finds that the following amendments and clarifications to Order No. 10–B are appropriate: (1) The escrow account procedure, and all references to it, are deleted; (2) all references to "voluntary" agreement are deleted; (3) the interest rate provision is amended; and (4) filing requirements are established in accordance with Order No. 10–B. The March 30 Order is amended and clarified by deleting paragraph (N) and the references to "voluntary" agreement and "further selection" of escrow account.

III. Issues

A. The Full Refund Obligation of the Corporate Undertaking

The Commission, in Order Nos. 10 and 10–A, required the interstate pipelines to escrow all funds collected from their gas customers for the First Use Tax. In their applications for rehearing of Order No. 10–A, many pipelines referred to legal opinions stating that Louisiana would provide full refunds if the First Use Tax is found unconstitutional.[17] Based on these arguments the Commission, in Order No. 10–B, established a corporate undertaking, subject to conditions, as an alternative to the escrow account.

All eighteen pipelines which have filed tariffs to recover the First Use Tax selected the corporate undertaking procedure. In this regard, Tennessee stated that, since 1971, when the Commission adopted a corporate undertaking requirement as a condition precedent to a pipeline collecting rates subject to refund,[18] "pipelines have collected billions of dollars (over $1.7 billion in fiscal year 1977 alone) subject to refund" and "there is no instance in which (Tennessee is) aware in which a pipeline has failed to comply with this undertaking commitment."[19] Because many pipelines have concluded that Louisiana will provide full refunds if the First Use Tax is found unconstitutional, because all eighteen pipelines have selected the corporate undertaking, and because this Commission's experience with the corporate undertaking provision in § 154.67 indicates that it adequately protects pipeline customers, the Commission modifies § 154.38(h) by deleting the escrow account procedure.

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[14] *Arkansas Louisiana Gas Co., et al.*, Docket Nos. RP79–53, RP79–54, *et al.*, "Order Accepting Certain Tariff Sheets, Conditionally Accepting Certain Tariff Sheets and Rejecting Certain Other Tariff Sheets Which Reflect the Louisiana First Use Tax in Pipeline Rates Pursuant to Order Nos. 10, 10–A, and 10–B" (March 30, 1979), 44 FR 21330 (April 10, 1979) (hereinafter "March 30 Order").

[15] *Arkansas Louisiana Gas Co., et al.*, Docket Nos. RP79–53, RP79–54, *et al.*, "Order Accepting Revised Tariff Sheets" issued May 9, 1979 ("May 9 Order").

[16] Michigan Wisconsin Pipe Line Company, Natural Gas Pipeline Company of America, Northern Natural Gas Company, Panhandle Eastern Pipe Line Company, Sea Robin Pipeline Company, Southern Natural Gas Company, Tennessee Gas Pipeline Company, Texas Gas Transmission Corporation, Trunkline Gas Company, Transcontinental Gas Pipe Line Corporation, United Gas Pipe Line Company, and Texas Eastern Transmission Corporation.

[17] Order No. 10–B, 44 FR at 13461–13462.

[18] See 18 CFR 154.67(c).

[19] *Tennessee Gas Pipeline Company*, Docket No. RP79–52, "Application of Tennessee Gas Pipeline Company, a Division of Tenneco, Inc., For Rehearing and Reconsideration and Motion For Stay Pending Completion of Judicial Review" at page 6 (filed April 20, 1979).

The Commission will retain the corporate undertaking provision and the requirement that pipelines make full refunds plus interest upon a final and non-appealable court order finding the First Use Tax unconstitutional. In the absence of this refund requirement, the ultimate consumers might be required to bear the cost of a tax found unconstitutional simply because the taxing state fails to refund the amounts which it collected. The refund provision assures that the taxpayer-pipelines will vigorously pursue refunds from Louisiana upon a final and non-appealable court order finding the First Use Tax unconstitutional.

The Commission has an affirmative duty to protect consumers, *e.g., California* v. *Southland Royalty Co.*, 436 U.S. 519, 523–524 (1978), and "to allow (regulated companies) only such rates as will prevent consumers from being charged any unnecessary or illegal costs." *NAACP* v. *Federal Power Commission*, 425 U.S. 662, 666 (1976) (footnote omitted); *Acker* v. *United States*, 298 U.S. 426, 430–431 (1936); *Cities Service Gas Co.* v. *Federal Power Commission*, 424 F. 2d 411, 417 (10th Cir. 1969); *Safe Harbour Water Power Corp.* v. *Federal Power Commission*, 179 F. 2d 179, 199–200 (3d Cir. 1949). Any portion of a tax which has been found to be unconstitutional is clearly an "unnecessary," if not "illegal," cost. *Cf. Tennessee Natural Gas Lines, Inc.* v. *Federal Power Commission*, 221 F. 2d 531 (D.C. Cir. 1954). Compare *Safe Harbour Water Power Corp.* v. *Federal Power Commission*, 179 F. 2d 179, 199–200 (holding that a company is not entitled to recover its actual cost of debt where it could refinance at a lower interest rate). If the First Use Tax, or any portion thereof, is held unconstitutional, the increased charges attributable to that tax are not properly chargeable to consumers. In such circumstances, consumers are entitled to prompt refund of the amounts attributable to such tax payments. *Federal Power Commission* v. *Tennessee Gas Transmission Co.*, 371 U.S. 145, 154–155 (1962); *Tennessee Natural Gas Lines, Inc.* v. *Federal Power Commission, supra.* Such refunds provide, at best, inadequate recompense to consumers for the illegal charges paid while the validity of the tax is litigated. *Cf. Federal Power Commission* v. *Hunt*, 376 U.S. 515, 524–525 (1964); *Federal Power Commission* v. *Tennessee Gas Transmission Co.*, 371 U.S. 145, 154–155 (1962). To reduce those refunds by any amounts not immediately refunded to the taxpayer-pipelines by the state would render the consumers' rights to refunds even more inadequate.

The requirement of full refunds also ensures that the taxpayer-pipelines will vigorously prosecute suits for refund of the First Use Tax payments submitted under protest. Under Louisiana law, the only procedure for challenging the constitutionality of a Louisiana state tax is a suit for refund of the tax paid under protest. La. Rev. Stat. §§ 47:1575, 47:1576. Only the taxpayer may bring such a suit. And, if the state does not refund all amounts paid under protest, the taxpayer probably would be the only person with standing to bring a suit to compel Louisiana to make refunds in accordance with La. Rev. Stat. § 47:1576(A). In such circumstances, the taxpayer-pipelines are not unduly burdened by the requirement that they promptly refund all amounts collected from their customers, since, if Louisiana does not refund all amounts collected subject to the refund, they (and, perhaps, only they) can sue to compel such refunds.

The pipelines will incur losses only if Louisiana does not refund all amounts paid under protest together with interest. Most pipelines collecting the

First Use Tax pursuant to § 154.38(h) [20] and several Louisiana officials [21] have assured the Commission that Louisiana will promptly refund all amounts paid under protest if the First Use Tax is held unconstitutional.[22] Indeed, should the state fail to make full refunds, the pipelines could bring suit in federal court to compel such refunds, since in those circumstances they may not have a "plain, speedy, and efficient remedy" (28 U.S.C. 1341) in the state courts, *Cf. Mississippi River Fuel Corp.* v. *Cocreham*, 382 F.2d 929, 932–934 (5th Cir. 1967). Accordingly, it is most unlikely that the pipelines will even be exposed to any significant risk of loss, much less acutally suffer any losses, as a result of the refund requirement.

Thus, pipelines losses, if they materialize, would be limited to interest costs during the time between payment of refunds to their customers and the time Louisiana refunds the money. Since Louisiana may make refunds at only 6% per annum,[23] these losses will be limited to the difference between the prevailing interest rate and the 6% interest rate. Pipeline customers, however, will have incurred similar interest losses throughout the pendency of litigation of the constitutionality of the First Use Tax. If the interest rate of refunds is not increased above the 6% level,[24] pipeline customers will incur losses because of the difference between the prevailing interest rate and the 6% interest rate. While pipeline customers are now suffering real and measurable losses, the pipelines' potential losses are speculative—Louisiana would have to refuse to refund taxes paid under a tax found unconstitutional before any pipeline losses occur. Even if this very speculative event should occur, the duration of the litigation of this issue will probably be shorter than the duration of the litigation of the constitutionality of the First Use Tax, and therefore the magnitude of potential losses by the pipelines would not approach the losses suffered by the pipeline customers.

The establishment of the special tracking mechanism with its full refund provision balances the interests and burdens of pipelines and their customers. Without the special tracking mechanism, the pipelines would have had to file a general section 4 rate case in order to recover the cost of the First Use Tax. Since in a section 4 general rate increase proceeding the increased cost of the First Use Tax might be offset by a decrease in the cost of another item in the overall cost of service, the special tracking provision might allow pipelines higher rates than if they were required to file a section 4 rate case to recover the First Use Tax.[25] The Commission has balanced this potential benefit to pipelines—*i.e.*, lack of exposure to offsetting rate decreases—against the benefit to the pipeline's gas customers of full refunds upon a final court determination that the First Use Tax is unconstitutional.

B. Refund Interest Rate

Order No. 10–B requires refunds "with corresponding interest at the refund interest rate under Louisiana law, but not less than 6% per annum." [26] As previously stated, six percent per annum is the present interest rate on refunds under Louisiana law. La. Rev. Stat. § 47:1576(A). The Commission believes this rate to be an inadequate interest rate.[27] In Order 10–B the Commission allowed a higher interest rate if the interest rate was changed "under Louisiana law." This language needs further clarification since the interest rate could be changed by the Louisiana legislature, by Louisiana state courts, or by federal courts.[28] Therefore, the interest rate provision is amended to read: "together with corresponding interest at the rate of 6 percent per annum; in the event that the State of Louisiana is required to make refunds with interest at a rate greater than 6 percent per annum, the pipeline shall refund all interest in excess of 6 percent per annum received from Louisiana. The pipeline shall make refunds with 6 percent interest within 60 days even if the State of Louisiana has not yet refunded, or does not refund, the tax payments plus interest to the pipeline; when refunds are received from the State of Louisiana, the pipelines shall refund immediately all interest, if any, in excess of 6 percent received from the State of Louisiana."

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[20] Order No. 10–B, 44 FR at 13481.

[21] *Ibid.*

[22] Some pipelines have asserted that Louisiana's failure to refund all amounts collected under an unconstitutional tax is unlawful. See, *e.g., United Gas Pipe Line Company, et al.*, Docket No. RP79–44, *et al.*, "Joint Application for Rehearing and Motion for Stay" at 7 (filed April 24, 1979).

[23] Six percent per annum is the present interest rate on refunds under Louisiana Law. La. Rev. Stat. § 47:1576(A).

[24] The plaintiffs in *Maryland, et al.* v. *Louisiana, supra*, seek refund of all amounts collected under the First Use Tax together with all interest earned on such amounts.

[25] *See* Order 10–A, 43 FR 60441 (December 28, 1978) and Application of Associated Gas Distributors for Rehearing and Reconsideration of Order No. 10 at 3–4. (filed September 27, 1978)

[26] Order No. 10–B, 44 FR at 13404 (18 CFR 154.38(h)(5)(i)).

C. Termination of Tracking Provisions

Several pipelines question this Commission's termination of the tracking provisions after final court determination of the constitutionality of the First Use Tax. They claim that they will incur significant losses between the termination date and the filing of their next section 4 rate case if the First Use Tax is found constitutional. This issue is premature; it will be addressed when the tracking provisions are terminated. At that time the Commission will know what further liability, if any, exists for the First Use Tax.

D. Compliance With La. Rev. Stat. § 47:1576

Order No. 10–B required pipelines to "submit such evidence as the Commission shall require in order to determine whether the procedures set out in La. Rev. Stat. § 47:1576 have been complied with."[29] Order No. 10–B did not detail what was required to meet this requirement. The Commission therefore amends Order No. 10–B to require pipelines to file with this Commission:[30] (1) A copy of all complaints filed in Louisiana protesting the constitutionality of the First Use Tax; and (2) reports summarizing the status of the proceedings instituted by, or against, the pipelines, to be submitted on or before June 1, 1980, and every three months thereafter. These filing requirements will allow the Commission to monitor more effectively pipeline challenges to the First Use Tax.[31]

IV. Proceeding To Determine Which Persons Should Bear the First Use Tax

Order No. 10–B required those interstate "pipelines (collecting the First Use Tax pursuant to § 154.38(h) to) take all legal action necessary to enforce contract provisions which could require the other contracting party to pay for the First Use Tax." 44 FR at 13464 (18 CFR 154.38(h)(6)). The Commission has determined that this matter is also governed by orders and certificates issued by the Commission as well as contracts between the pipelines and the owners of liquid and liquefiable hydrocarbons, many of which have been incorporated into certificates of public convenience and necessity issued by this Commission or the Federal Power Commission. Accordingly, the Commission is today instituting proceedings in Docket No. RM78-23 (Phase II) to resolve the question of whether persons other than natural gas consumers should pay the First Use Tax, subject to refund, while its constitutionality is litigated.

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[27] The Commission's refund interest rate for the second quarter of 1980 is 15.39%. Louisiana will make money if it refunds to pipelines with only 6% interest. State Representative Tauzin noted the benefit to Louisiana of a 6% interest rate (*Senate hearings* at 6):

> So that the total amount that we might be liable for in the event that we should lose the litigation is available for refund at 6% interest. We are likely to make more than 6% interest on it in investments. We are actually going to probably come out a little bit ahead on it.

In light of the increase in interest rates since the First Use Tax went into effect (April 1979), State Representative Tauzin's prediction understates the benefit to Louisiana.

[28] *See* note 24, *supra.*

[29] Order No. 10–B, p. 21.

[30] The above-quoted language accordingly is deleted.

[31] The pipelines are encouraged to file jointly one report and one copy of the complaint filed in *Southern Natural Gas Co., et al.* v. *McNamara, et al.*, No. 225–553 (19th Judicial District Court, Louisiana), and any other cases seeking refund of the amounts paid under protest.

V. Effective Date

The Commission is making these amendments effective upon the date of issuance of this order upon a finding that good cause exists to proceed without compliance with the effective date provisions of 5 U.S.C. 553. The amendments of Order 10-B contained herein reduce the burdens on the pipelines (escrow provisions are deleted), allow the Commission to monitor more effectively pipeline challenges to the First Use Tax, further clarify the refund provisions to protect the pipelines' customers, and allow for expeditious court review of Order Nos. 10, 10-A, 10-B, and this order. The Commission therefore finds good cause exists to make these amendments effective upon issuance of this order. (Natural Gas Act, 15 U.S.C. 717 c, f, o); Administrative Procedure Act (5 U.S.C. 553); Department of Energy Organization Act, (42 U.S.C. 7101, *et seq.*); and E.O. 12009, (42 FR 46267).

In consideration of the foregoing, the Commission hereby orders that:

(A) The Commission's Order Nos. 10, 10-A, and 10-B and the March 30 Order are amended and clarified consistent with this order.

(B) Paragraph (N) of the March 30 order is deleted.

(C) Part 154, Chapter I of Title 18, The Code of Federal Regulations, is amended as set forth below, to become effective as of the date of issuance of this order:

By the Commission.
Kenneth F. Plumb,
Secretary.

[¶ 30,149]

45 F. R. 29569 (May 5, 1980)

18 CFR Parts 270 and 271
[Docket No. RM80-53]

Rules Generally Applicable to Regulated Sales of Natural Gas and Definitions and Ceiling Prices; Order of the Director, OPPR of Publication of Maximum Lawful Prices Under Title I of the NGPA

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: Pursuant to the authority delegated by 18 CFR § 375.307(1), the Director of the Office of Pipeline and Producer Regulation revises and publishes the maximum lawful prices prescribed under Title I of the NGPA. Section 101(b)(6) of the NGPA requires that the Commission compute and publish maximum lawful prices under Title I at the beginning of each month for which such figures apply.

EFFECTIVE DATE: April 25, 1980.

FOR FURTHER INFORMATION CONTACT: Kenneth A. Williams, Federal Energy Regulatory Commission, 825 N. Capitol Street NE., Washington, D.C. 20426 (202) 357-8500.

Order of the Director, OPPR

Issued April 25, 1980.

Publication of prescribed maximum lawful prices under the Natural Gas Policy Act of 1978.

Section 101(b)(6) of the NGPA requires that the Commission compute and make available maximum lawful prices prescribed in Title I and inflation adjustments before the beginning of any month for which such figures apply.

Pursuant to that mandate and pursuant to § 375.307(1) of the Commission's regulations, delegating the publication of such prices and inflation adjustments to the Director of the Office of Pipeline and Producer Regulation, the maximum lawful prices for the months of May, June, and July 1980, are issued by the publication of price tables for the applicable quarter. Pricing tables may be found in § 271.101(a) of the Commission's regulations. Table I of § 271.101(a) specifies the maximum lawful prices for gas subject to section 102, 103, 106(b)(1)(B), 107, 108 and 109 of the NGPA. Table II of § 271.101(a) specifies the maximum lawful prices for section 104 and 106(a); Table III of § 271.102(a) sets forth the inflation adjustment.

Paul Hubbard,
Designee of the Director, Office of the Pipeline and Producer Regulation.

[¶ 30,150]

45 F. R. 30066 (May 7, 1980)

18 CFR Parts 141, 260

[Docket No. RM80-2; Order No. 79]

Discontinuance of Collection of Data, Under FPC Forms Nos. 3, 3A, 3P, and 82

May 1, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission hereby discontinues the collection of data under FPC Forms No. 3, No. 3A, No. 3P, and No. 82 because the information contained in these forms is no longer needed by the Commission to carry out its regulatory responsibilities. With respect to Form No. 40, the Commission is discontinuing the collection of detailed data which relates to gas reservoirs. Other information in this latter form concerning the gas reserves commitment status continues to be necessary to the Commission to fulfill its regulatory responsibilities. This information will, therefore, continue to be collected on behalf of the Commission by the Energy Information Administration.

EFFECTIVE DATE: May 1, 1980.

FOR FURTHER INFORMATION CONTACT:

(Forms Nos. 3, 3A, 3P, and 82) Daniel G. Lewis, Federal Energy Regulatory Commission, Office of Electric Power Regulation, 825 N. Capitol Street NE., Mail Stop 300 RB, Washington, D.C. 20426, (202) 376-9227.

(Form No. 40) B. William Herbert, Federal Energy Regulatory Commission, Office of Pipeline and Producer Regulation, 825 N. Capitol Street NE., Mail Stop 3100N, Washington, D.C. 20426, (202) 357-9091.

I. Background

On October 23, 1979, the Federal Energy Regulatory Commission (Commission) issued a Notice of Proposed Rulemaking (44 FR 61976, October 29, 1979). The rulemaking proposed to discontinue use of FPC Forms No. 3, 3A, 3P, 40 and 82.

Form No. 40 expired in March 1978. The Commission no longer requires the detailed gas reservoir information from Form No. 40. Information concerning the gas reserves commitment status is, however, still necessary to the Commission's regulatory responsibilities. The Energy Information Administration (EIA) is now authorized to collect such data.[1] As a result, Form No. 40 has been superseded by EIA's Form EIA-23. Among the data on Form EIA-23 are those which relate to the gas reserves commitment, and this information is transmitted to the Commission by EIA.

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[1] Federal Energy Administration Act (15 U.S.C. 761, *et seq.*), as amended by section 205 of the DOE Act.

Forms No. 3, 3A, 3P and 82 were established under authority granted to the Federal Power Commission (FPC) (the Commission's predecessor agency) by section 311 of the Federal Power Act (FPA) (16 U.S.C. 791(a), *et seq.*).[2] The Commission's authority under section 311 was transferred to the Secretary of Energy pursuant to section 301(b) of the Department of Energy Organization Act (DOE Act) (42 U.S.C. 7101, *et seq.*).[3] The Secretary in turn delegated this authority to EIA [4] and to the Commission to the extent needed to perform its other vested or delegated functions.[5] Because of these changes in the Commission's regulatory responsibilities, the Commission no longer requires the data from these forms to perform its statutory or delegated functions.

II. Discontinued Forms

Nine comments were received in this docket. Based upon a review of these comments and its own analysis, the Commission by this final rule discontinues collection of the five forms described below.

Form No. 3—Typical Net Monthly Bills for Electric Service (18 CFR 141.21). Form No. 3 was submitted annually by utilities. It was designed to obtain information concerning monthly bills for specific quantities of electric service to certain customers. Form EIA-213 is now being used by EIA to collect this information.

Form No. 3A—All-Electric Homes Data Sheet (no CFR reference) (expired June 30, 1979.) Form No. 3A was voluntarily filed by utilities on an annual basis. Neither the Commission nor EIA now uses the information contained therein; the form, therefore, is discontinued by this final rule.

Form 3P—Residential Electric Bill Data for the U.S. Bureau of Labor Statistics (18 CFR 141.28). Form 3P was designed to secure monthly electric bill data from electric utilities and was submitted by the Commission to the U.S. Bureau of Labor Statistics (BLS). EIA now collects the data for BLS on Form EIA-101.

Form No. 40—Natural Gas Companies Annual Report of Proved Domestic Gas Reserves (18 CFR 260.13) (expired March, 1978). Form No. 40 required certain natural gas companies to submit to the Commission an annual report of proved domestic reserves. These data are now collected by EIA on its Form EIA-23. Information in Form EIA-23 concerning the gas reserves commitment status is gathered by EIA on behalf of the Commission to fulfill the Commission's regulatory responsibilities.

Form No. 82—Retail Rate Level Change (18 CFR 141.27) (expired June 30 1978). Form No. 82 was designed to secure from electric utilities, within 60 days of the effective date of a new retail rate schedule, the 12-month dollar effect of such change. Neither the Commission nor EIA needs the information contained in the form; it is therefore discontinued.

III. Summary of Comments

In response to the proposed rulemaking, the Commission received comments from the Energy Information Administration and nine public respondents including six electric utilities, two natural gas companies, and one university. EIA concurred in the discontinuance of Forms No. 3A and 82. EIA also indicated that it is presently collecting the data contained in FPC Forms No. 3, 3P, and 40.

The general reaction to the rulemaking from the public commentors was very favorable. Three respondents, however, expressed a need for some of the data contained in Form 3 and stated that the continued collection of the information by either the Commission or EIA is necessary. As noted above, EIA is presently collecting the information from Form No. 3 on its own Form No. EIA-213.

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[2] Section 311 authorizes the Commission to conduct investigations regarding the generation, transmission, distribution and sale of electric energy.

[3] Section 301(b) vests in the Secretary the powers of the FPC under the FPA and the Natural Gas Act (NGA) (15 U.S.C. 717, *et seq.*) which were not transferred to the Commission by Title IV of the DOE Act.

[4] Department of Energy Delegation Order No. 0204-3, October 1, 1977.

[5] Department of Energy Delegation Order No. 0204-1, October 1, 1977.

One commentor objected to the discontinuation of Form 3A because of the public's interest in the information. The Commission recognizes that the public might have some interest in the information collected by way of this form but does not believe that this reason by itself justifies continued collection of the information by the Commission. As stated above, the data collected in these forms is not needed by the Commission to perform its regulatory responsibilities.

IV. Public Procedure and Effective Date

The Commission has complied with 5 U.S.C. 553 by having provided public notice and an opportunity to participate in this rulemaking. Adoption of this rulemaking will eliminate a requirement imposed on industries regulated by the Commission. Therefore, the Commission finds good cause to waive the 30-day requirement set forth in 5 U.S.C. 553(d) and to make this final rule effective immediately. Thus, Forms No. 3, 3A, 3P, 40, and 82 are discontinued as of the date of issuance of this rule.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; E.O. 12009, 42 FR 46267.)

For the reasons stated above, the Commission hereby discontinues Forms No. 3, 3A, 3P, 40, and 82, effective immediately.

In addition, in consideration of the foregoing, the Commission amends Parts 141 and 260 of Chapter I, Title 18, Code of Federal Regulations, as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,151]

45 F. R. 30068 (May 7, 1980)

18 CFR Part 273

[Docket No. RM79-53]

Natural Gas; Order Extending Period for Interim Collections Pending Jurisdictional Agency Determination

April 30, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: This order amends § 273.202(b)(2)(i) of the Federal Energy Regulatory Commission's regulations implementing the Natural Gas Policy Act of 1978 (NGPA). The amendment extends the period during which sellers of natural gas are authorized to make interim collections of NGPA ceiling prices pending a jurisdictional agency determination of eligibility until July 31, 1980.

EFFECTIVE DATE: April 30, 1980.

FOR FURTHER INFORMATION CONTACT: Roger B. Coven, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-9124.

On June 19, 1979, the Federal Energy Regulatory Commission (Commission) issued final Part 273 Regulations Implementing the Natural Gas Policy Act of 1978 (NGPA).[1] Subpart B of Part 273 established rules governing interim collection of NGPA ceiling prices pending jurisdictional agency determinations of eligibility. Subject to certain restrictions not relevant here,

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[1] Order No. 36, Docket No. RM79-53 (June 19, 1979).

§ 273.202(b)(2) provides that interim collections can be made during the period that an application for determination is pending before a jurisdictional agency until the earlier of:

> (i) 12 months after the first delivery for which collection is made under this section (18 months in the case of deliveries beginning before May 1, 1979); or
>
> (ii) The date on which the Commission receives a notice of jurisdictional agency determination under § 274.104.

Under § 273.202(b)(2), interim collection authority will terminate for some sellers subject to the 12 month limitation on May 1, 1980. Interim collection authority for sellers who filed shortly after December 1, 1978, will begin to expire under the 18 month limitation in early June, 1980.

The Commission has received written requests from three jurisdictional agencies to extend the period during which interim collections can be made.[1] The jurisdictional agencies stated that massive volumes of filings have been received and that due to limited manpower, processing cannot be completed before interim collection authority terminates with respect to many of the filings.[3]

The Commission understands that the initial flow of well determination filings to the jurisdictional agencies has been great. Furthermore, the Commission believes that expiration of interim collection authority due to the resulting backlog of filings would cause unnecessary hardship and administrative and accounting burdens for sellers. In the order which established final Part 273 regulations we stated, "[i]f it becomes apparent that the time limitation is likely to cause a problem, we may consider a revision of the rule."[4] The Commission believes that such a problem does exist based on the information submitted by the three jurisdictional agencies mentioned above.

Accordingly, we amend § 273.202(b)(2) to provide that the period during which interim collections can be made will not expire prior to July 31, 1980, unless the Commission receives a notice of jurisdictional agency determination under § 274.104.[5] The Commission believes that this extension should be sufficient to allow jurisdictional agencies to catch up with the backlog of well determination filings.

In view of the need for prompt Commission action in these circumstances to prevent the expiration of interim collection authority for certain sellers of natural gas, and since notice and opportunity for comment are impracticable, unnecessary and contrary to the public interest, the Commission finds that good cause exists to issue these amendments without opportunity for notice and public procedure thereon.

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[1] The West Virginia Oil & Gas Division, Department of Mines and the United States Geological Survey in Casper, Wyoming requested a 90 day extension of the interim collection period. The Railroad Commission of Texas petitioned the Commission to amend § 273.202(b)(2) so that interim collection authority would not terminate prior to August 1, 1980.

On April 25, 1980, Indicated Producers filed a Joint Petition of Indicated Producers For Modification of the Commission's Rules and Regulations Pertaining to Interim Collections in which they support the request of West Virginia and Texas for an extension of time. Although the Indicated Producers urged a modification of § 273.202(b)(2) that would permit greater extensions of the interim collection period, the Commission believes that the extension allowed by this order will be adequate.

In another petition filed with the Commission, the Interstate Oil Compact Commission (Compact) supports the petitions of Texas and West Virginia. Furthermore, Compact states that it is joined in its petition by the Corporation Commission of the State of Oklahoma and the Oil Conservation Division of the Energy and Minerals Department of the State of New Mexico.

[3] The West Virginia Oil & Gas Division states that it has reviewed over 16,000 applications for determination and that nearly 1,000 applications remain to be reviewed for which interim collection authority will cease if the requested extension is not granted. Of the filings that have been reviewed, about 4,000 have yet to be fully processed and forwarded to the Commission.

[4] Order No. 36, Docket No. RM79-53 (June 18, 1979), mimeo at 9-10.

[5] Once a notice of an affirmative determination by a jurisdictional agency has been received by the Commission, the seller may be authorized to make interim collections under § 273.202.

For the same reasons, good cause exists to issue these regulations effective immediately.

(Natural Gas Act, as amended 15 U.S.C. 717-717w; Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3432; Department of Energy Organization Act, 42 U.S.C. 7101-7352. E.O. 12009, 42 FR 46267.)

In consideration of the foregoing, Part 273 of Subchapter H, Chapter I, Title 18, Code of Federal Regulations, is amended as set forth below effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,152]

45 F. R. 31059 (May 12, 1980)

18 CFR Part 1

[Docket No. RM80-26; Order No. 82]

Rules of Practice and Procedure; Interlocutory Appeals from Rulings of Presiding Officers

May 2, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: To clarify inconsistent language the Federal Energy Regulatory Commission (Commission) is amending § 1.28 of the rules of practice and procedure (18 CFR 1.28) to provide for interlocutory appeals to the Commission from rulings of presiding officers.

DATE: June 9, 1980.

FOR FURTHER INFORMATION CONTACT: June G. Perin, Office of the General Counsel, Federal Energy Regulatory Commission, 825 N. Capitol St. NE., Room 8000, Washington, D.C. 20426, (202) 357-8457.

SUPPLEMENTARY INFORMATION:

Background

The Federal Energy Regulatory Commission (Commission) is amending § 1.28 of the rules of practice and procedure pertaining to interlocutory appeals to the Commission from rulings of presiding officers. The rule as amended provides for an appeal to the Chairman or a member of the Commission designated by the Chairman ("designated Commissioner"), of a presiding officer's denial of a request to refer a ruling. Upon the designated Commissioner's determination, a matter may be referred to the full Commission for review. The rule, as amended will apply to all on the record proceedings.

Section 1.28(a) as presently written prohibits interlocutory appeals from rulings of presiding officers made during the course of hearings or conferences unless the presiding officer finds that extraordinary circumstances exist and that prompt decision by the Commission is necessary to prevent detriment to the public interest. If the presiding officer makes such a finding, he is required to refer the matter to the Commission immediately.[1] Appeals to the Commission from a presiding officer's denial of a request to refer a ruling are not provided for in § 1.28(a).

However, there is an inconsistency between § 1.28(a) and § 1.28(c). Section 1.28(c) provides that unless the Commission acts within 30 days "* * * upon questions referred by presiding officers to the Commission for determination or upon *appeals* taken to the Commission from rulings of presiding officers * * * *such referrals or appeals* shall be deemed to have been denied." Thus, even though § 1.28(a) proscribes appeals to the Commission unless a referral is made by the presiding officer, § 1.28(c) contains a reference to both referrals and appeals.[2] The reference to "appeals" in § 1.28(c) has resulted in a current practice where appeals are directed to the Commission in cases where the presiding officer has not deemed the matter worthy of referral. To a large extent this practice is the result of the inconsistent language between § 1.28 (a) and (c).

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[1] Additionally, under § 1.27(b)(8) a presiding officer may in his discretion, or at the direction of the Commission, certify any question to the Commission for its consideration and disposition. This rulemaking does not affect a presiding officer's, or the Commission's authority, under § 1.27(b)(8).

The purpose of this rulemaking is to resolve the inconsistency between § 1.28 (a) and (c). The general prohibition against interlocutory appeals remains, but an appeal to the designated Commissioner, of a presiding officer's denial of a request to refer a ruling is provided for. In this case, the appeal will be referred to the Commission only if the applicant demonstrates and the designated Commissioner finds that extraordinary circumstances exist which necessitate prompt Commission review to prevent detriment to the public interest.

By amending § 1.28 in this manner the Commission does not intend to encourage interlocutory appeals. On this point, the Commission affirms its policy that the orderly and expeditious conduct or proceedings is best achieved when the presiding officer controls the course of litigation. As a result, interlocutory appeals or motions which have a similar effect that are filed in a manner not provided for by this rule will not be entertained.

II. Summary of the Amended Regulations

Section 1.28 as amended by this rulemaking, provides that a participant in a proceeding may request the referral to the Commission of a ruling made by the presiding officer during the course of the proceeding. If the presiding officer determines that extraordinary circumstances exist such that prompt Commission review of the contested ruling is necessary to prevent detriment to the public interest or if the ruling of the presiding officer would require that a contested order under § 1.33 not be stayed or that the stay of such order be lifted, immediate referral to the Commission is required. Unless the Commission acts on a matter referred to it by a presiding officer within 15 days, the ruling of the presiding officer will be deemed affirmed.

The presiding officer is required to notify all participants of his determination and of the date of any referral to the commission. If the presiding officer fails to make a determination that prompt Commission review is necessary to prevent detriment to the public interest within 15 days after the receipt of a request, the request will be deemed denied.

Section 1.28 also provides for an appeal to the designated Commissioner of a presiding officer's denial of a request to refer a ruling. The appeal must be filed within 7 days after the date the request is denied or deemed denied and must fully explain: why prompt Commission review is necessary, how the circumstances are extraordinary, and what detriment to the public interest will result if prompt Commission review is denied. In addition, if the presiding office has denied the request either by way of written order or orally, a copy of the order or the relevant portions of the transcript must be filed with the appeal.

In order to facilitate or expedite the review, the designated member may request additional written information from the presiding officer or any participant in the proceeding. Responsive pleadings from participants other than those from whom the designated Commissioner has requested information are not permitted.

Unless the designated Commissioner refers the appeal to the Commission within 7 days after its filing, the contested ruling of the presiding officer will not be reviewed by the Commission until the Commission considers the proceeding with respect to which the ruling was made. A request for information by the designated Commissioner will not serve as a basis for extension of this time period.

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[2] Order No. 217, issued November 20, 1958, in Docket No. R-177, amended § 1.18(d) of the rules of practice and procedure to provide for an immediate appeal to the Commission from the rulings of a presiding officer made during conferences. Order No. 217 also amended § 1.28 by adding paragraph (c). In this context the reference to "appeals" in paragraph (c) was appropriate. However, in Order No. 273, issued November 12, 1966, in Docket No. R-351, the immediate appeal provision of § 1.18(d) was deleted but the reference to "appeals" contained in § 1.28(c) was not.

If it is determined that extraordinary circumstances exist which necessitate prompt Commission review to prevent detriment to the public interest, the matter will be referred to the Commission. The Secretary is required to notify all participants in the proceeding of any determination to refer to the Commission. Unless the Commission acts within 15 days after receipt of the referral, the ruling of the presiding officer will be deemed affirmed.

As amended, § 1.28 provides that any action taken under this section will not operate to suspend the proceedings unless otherwise ordered by the presiding officer or the designated Commissioner. Finally, the substance of § 1.28(b) pertaining to offers of proof remains unchanged but has been redesignated as § 1.28(f).

Effective Date

The Commission issues this rule effective on June 9, 1980. The rule merely amends the procedures relating to interlocutory appeals from rulings of presiding officers. Since the rule is strictly procedural in nature, Section 553 of the Administrative Procedure Act (5 U.S.C. 553) does not require prior notice and opportunity to comment.

(Natural Gas Act, *as amended* (15 U.S.C. 717, *et seq.*) Federal Power Act, *as amended*, (16 U.S.C. 791, *et seq.*) Interstate Commerce Act, (49 U.S.C. 1, *et seq.*), Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.*; E.O. 12009, 42 FR 46267)

In consideration of the foregoing, the Commission amends Part 1, Chapter I of Title 18, Code of Federal Regulations as set forth below, effective on June 9, 1980.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,153]

45 F. R. 31294 (May 13, 1980)

18 CFR Part 35

[Order No. 84; Docket No. RM79-29]

Filing of Rate Schedules; Regulations Limiting Percentage Adders in Electric Rates for Transmission Services

May 7, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) adopts regulations that require electric utilities or systems to limit the amount of revenue recovered under percentage adders contained in rates used for transactions in which the utility or system transmits or purchases and resells wholesale electric power as part of a multiple party transaction. The rule requires limits on only those percentage adders that recover revenues computed wholly or in part as a percentage of the purchase price of electric power paid by a transmitting utility for power generated by another utility. All revenue limits must be supported by cost information, unless a percentage adder is limited at one mill per kilowatt-hour or less.

The Commission adopts this rule to prevent overrecovery of costs by means of percentage adders. Charges under these rate components are added to the cost of power by each intervening transmitting utility or system during multiple party transactions. In addition, percentage adders recover revenues based largely on the costs incurred by the utility or system that originally generates the power, which costs have been swollen by increases in the price of fuel in recent years.

The final rule will ensure that revenues recovered under percentage adders used for transmission services, including purchases and resales of power, and based on the purchased

power price will more closely approximate certain operational costs incurred by transmitters.

EFFECTIVE DATE: June 11, 1980.

FOR FURTHER INFORMATION CONTACT:

Robert Cackowski, Office of Electric Power Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street N.E., Washington, D.C. 20426, (202) 376-9229.

James Hoecker, Division of Regulatory Development, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street N.E., Washington, D.C. 20426, (202) 357-8342.

The Federal Energy Regulatory Commission (Commission) gives notice that it adopts a new § 35.23 which requires that revenue limits be placed on the operation of percentage adders in rate schedules used for the transmission or third party resale of electric power. For purposes of this rulemaking, a percentage adder is a rate component that recovers revenues computed wholly or in part as a percentage of the price of purchased electric power paid by a transmitting utility for power generated by another utility. The rule requires submittal of cost information to support the limits that are established for percentage adders used by a transmitting utility. If the utility limits such revenues to one mill per kilowatt-hour or less, cost support information is not required by the rule. Rate schedules must be revised to show the limit established for any percentage adder that is based on the price of the purchased power transmitted.

If a utility that performs a transmission or purchase and resale function computes a percentage adder charge on a different basis, as a percentage of only internal incremental costs other than the purchased power price, for example, this rule does not apply and no limitation is required.

The Commission will continue to study the question of what should be the appropriate level of revenues recovered by percentage adders in rates used by utilities or systems that generate the electric power delivered during interchange sales. Continued examination of this issue will also help the Commission assess the need for limits on percentage adders used by transmitting utilities if transmitters use only the internal incremental costs that they incur as a base for such adders.

I. Background

A. *History of the rulemaking.* Rate schedules currently on file contain adder percentage adders that cover a variety of miscellaneous costs in electric energy transactions. The economic dislocations caused by an oil embargo and a coal strike in the 1970's presented questions about the fairness of using percentage adders in multiple interchange transactions. The dimensions of the distortion in the relationship between costs and rates caused by these rate components were clearly evident in the Commission's coal strike report in 1979.[1] The report showed how adder charges may be compounded several times in a single interchange transaction without regard to the actual internal incremental costs incurred by each intervening utility. A percentage adder included by each intervening utility in the price of the transmitted power uses as all or part of its base the purchased power price. Only some of the transmitters may be replacing power lost in transmission. This purchased power price includes all adder charges previously assessed by other transmitting utilities.[2] This phenomenon becomes exacerbated as fuel costs escalate because revenues recovered by percentage adders increase in proportion to the increases in the incremental costs of generating power, not in proportion to the costs of transmitting it.

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[1] Report of the Designated Officer, Investigation Into Wholesale Power Transactions During Time of Fuel Inadequacies, March 19, 1979 (Docket No. ER78-307). The discussion of adders is found on pages 11-14 and Appendix I, pages 7-13.

[2] "For instance, short-term energy having an original out-of-pocket cost of $30/mwh may end up costing $50/mwh after moving through four systems (30×1.1×1.15×1.15×1.15)." These figures indicate that the intervening transmitting utilities added to the price of the power they purchased one 10% and three 15% charges. Id., Appendix I, at 14.

In light of these considerations, the Commission was persuaded that the percentage adders contained in electric rate schedules were no longer cost-justified in most circumstances. The Federal Power Act requires that utilities use just and reasonable rates. The Commission is required to implement this statutory requirement by requiring that rates be based on costs incurred by utilities.

Accordingly, the Commission issued a Notice of Proposed Rulemaking in this docket on April 4, 1979 [3] to establish limits for all percentage adders in electric rate schedules. Submittal of initial and reply comments was followed by oral presentations before the Commission. The proposed rule was designed to limit percentage adders in all electric rates according to whether a utility generated the electric power delivered or only transmitted it through an interconnection arrangement. The proposed rule set fixed monetary limits for revenues recovered under such adders, so that the use of percentage adders could be retained without allowing recovery of excessive revenues. Retention of percentage adders would, among other things, diminish the burden of revising rate schedules.

The Commission received comment on the rulemaking from ninety public utilities and cooperatives, six power-pooling organizations, sixteen municipal, state, and Federal entities, and three trade associations or related industries.[4] Sixteen of the commenters, including the Commission staff, made oral presentations before the Commission on June 4, 1979.

Most commenters dealt with the issues and problems presented by the proposed adder limits only as they affect generating utilities. Yet, the notice and comment procedure yielded a paucity of cost data from which the Commission could have established a reasonable limit on percentage adders relative to the unquantified incremental costs incurred by a utility that generates power, either as the original source system in an interchange transaction or for purposes of replacing transmission losses. Throughout the rulemaking process, the Commission focused its attention on the manner in which percentage adders are used by utilities that perform transmission or purchase and resale functions in multiple party transactions. The level of revenues charged the ultimate purchaser of the power was too high because it reflected compounded applications of percentage adders to the price of wheeled electric power. In addition, the Commission believed that there was a misapplication of the percentage adder to the price that each intervening utility pays for the power that it resells, that is, the "purchased power price." The Commission therefore adopts a final rule that applies only to rates used for transmission services and requires limits to be placed on percentage adders that are based, wholly or in part, on the purchased power price.

B. *The rule adopted.*

1. *Statement of the problem with percentage adders in rates used for transmission services.*

An "adder" is included in an electric rate to recover unquantifiable or expensive-to-quantify incremental energy costs. An adder may be a set charge per kilowatt-hour, that is, a

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[3] 44 FR 21863, April 11, 1979.

[4] The Commission consolidated the comment and oral presentation procedures in this docket with the comment procedures in Docket No. RM79-28. The rulemakings are somewhat similar to one another in limiting certain components of electric rates, although Docket No. RM79-28 applies only to emergencies under section 202(c) of the Federal Power Act. Most of the comments also addressed the special issues peculiar to electric rates used during emergencies declared under the Act. In this docket, the Commission is only concerned with limitations on percentage adders in non-emergency situations.

"fixed adder", or it may function as a percentage of quantifiable incremental costs, including the purchased power price, as a so-called "percentage adder."

Percentage adders are part of the energy component in a rate and their function is limited. Percentage adders are not designed to recover the fixed costs of capacity.[8] Nor do they provide a profit on capital investment. There are other components in the utility's electric rate schedule that recover fixed capacity costs and that provide the utility with a rate of return on investment. Recovery of fixed costs or of a return on investment through percentage adders would therefore constitute overrecovery of these costs.

Much of the misunderstanding among the commenters about the intent and effect of the proposed rule appears to have arisen from the varying justifications offered by commenters to explain how a percentage adder operates in a rate schedule. Percentage adders were variously described as compensation for fixed costs, incremental costs, risks taken by the generating utility, or error in the estimation of costs. It appears that many commenters believe that percentage adders should also provide an incentive to engage in interchange transactions, which presumably means some form of compensation beyond out-of-pocket and fully allocated costs. Arguably, adders may be justified for purposes other than cost recovery if there were no demand or reservation charge to provide an incentive to transact. However, other components of ordinary filed rates provide such incentives.

Some commenters maintain that percentage adders compensate a utility for risks undertaken by a utility to supply electric interchange power, such as depletion of difficult-to-replace fuel resources. To the extent that such a proposition may arguably be true, the fact remains that those risks are borne largely by generating systems.[9]

Among the rate components that capture incremental costs in the energy portion of a rate, the percentage adder is unique. Other rate components that recover incremental costs do so strictly on a dollar-for-dollar basis; that is, a utility's rates are designed to recover exactly the amount of its demonstrable incremental costs. By definition, percentage adders are a ratemaking convenience for recovering costs that cannot otherwise be easily demonstrated. Because of this fact, percentage adders have provided utilities an opportunity to recover revenues *in excess* of operating expenses, unlike other components of the energy portion of a rate.[7]

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[8] A major objection to the proposed rulemaking was that the one and two mill limitation on percentage adders for transmitting and generating utilities, respectively, would fail to provide sufficiently for fixed costs such as interest, depreciation, taxes, labor costs, administrative and general costs, or return on investment. It was argued that, during an interchange transaction of long duration, interchange customers should make some contribution to the fixed or investment costs of the seller. In rates used by transmitters or generators, recovery of fixed costs is the function of rate components other than percentage adders. The appropriate function of percentage adders in non-emergency transactions has been and remains the recovery of the difficult-to-quantify incremental costs.

[9] Many commenters argue that the adder is a means of compensating for uncertainties in incremental costs, underestimation of those costs, or taking risks to supply interchange power. Cost uncertainties, such as those involved in any replacement of fuel months or years after an interchange transaction, are problems faced by utilities that originally produce electric power. A commenter claims that even a 2.5 percent error in estimating transmission losses that must be replaced can consume a utility's margin for error under a percentage adder. Another alleges that transmission losses may run from 10 to 30 percent. Although such an estimate appears to be high, the Commission believes that compensation for transmission losses of that size can be specifically recovered, if justified, by a utility as a separately stated incremental cost. If a transmitting utility affected by this rule incurs costs when generating power to make-up for line losses during transmission, those costs are also quantifiable and should become part of the incremental rate. While the Commission recognizes that uncertainty in determining such incremental costs exists, it does not believe that the unrestricted use of percentage adders is appropriate protection from any and all degrees of uncertainty or a suitable substitute for the need to quantify or more accurately estimate any amount of a utility's costs.

Percentage adders recover revenues computed as a percentage, usually 10 percent,[8] of an incremental cost "base." This convenient mechanism may be reasonable for generating utilities because the adder is at least arguably derived from an appropriate base, *viz.*, the actual cost of producing a unit of power. Percentage adders applied to another utility's cost of generation, as is frequently done in the rates of utilities that provide only transmission or purchase and resale services, do not have this redeeming feature.

It is frequently argued, with some credibility, that an adder charge is appropriate as a rule of administrative convenience to prevent unnecessary expenditures of funds to quantify miscellaneous cost. This argument does not support use of unlimited percentage adders applied to the purchased power price. If, as now, the previously unquantified incremental costs that adders are designed to recover are increasing, it may become economically practical to quantify those costs as part of the incremental rate. The use of percentage adders as a rule of administrative convenience may still operate to save money by allowing utilities to recover, within limits, incidental or miscellaneous costs that remain economically impractical to quantify.[9]

In summary, there is generally no relationship between the purchased power price paid by transmitting utilities and those utilities' internal incremental costs which percentage adders recover. The purchased power price largely represents costs incurred by utilities that generate the power. Therefore, recovery of a transmitter's own unquantified incremental costs by means of a percentage adder applied to a base that includes the purchase power price is inappropriate unless the adder is permitted to recover only revenues limited to those internal incremental costs. Moreover, the problem is compounded because revenues recovered under percentage adders tend to increase geometrically according to the number of utilities that become parties to a multiple purchase and resale transaction. As a result, the final charge for the electric power may bear little relation to the actual costs of producing the power and transferring it to a receiving system.

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[7] Split-savings rates used in economy energy tranactions result in a similar kind of an expense-based recovery above costs. However, such a device has generally been considered acceptable both because there is a savings to the buying utility or system that would otherwise have to use a more expensive fuel to generate power and because there are no other rate components that would provide selling utilities incentives to transact. Thus, the combined costs incurred by the buying and selling utilities are less than what the cost would have been had the split-savings transaction not occurred.

Split-savings rates are based on the difference between the supplier's incremental cost and the buyer's decremental cost. Fifty percent of the difference is added to the supplier's incremental costs to form the energy portion of an economy energy rate. For example, where $10/mwh coal-fired energy displaces $20/mwh oil-fired energy, the energy is priced at $15/mwh. The seller realizes $5 above its out-of-pocket costs.

Many commenters were apprehensive that the proposed rule would affect the use of split-savings rates. Although the Commission recognized in the Notice of Proposed Rulemaking that split-savings rates may present cost control problems similar to those created by percentage adders, neither the proposed rule nor the final rule attempt to deal with cost justification of economy energy transactions conducted on a split-savings basis.

[8] In the case of third-party, short term firm energy, the adder is usually 15 percent.

Fuel conservation rates on file with the Commission for use in times of fuel shortages contain only fixed adder charges to cover demand-related costs and unquantifiables. These rates have been seldom used during past fuel shortages.

The Commission Order in Docket No. ER78-229, *et al.* sets forth adder principles for fuel conservation energy rates. While percentage adders for generation of power are capped at 2 mills/kilowatt-hour, such components are replaced by fixed adders for transmission services. Order Establishing Principles for Settlement of Fuel Conservation Energy Rate Schedule Proceedings and Providing for Filing, issued March 28, 1980, *mimeo* at 7-9 and Appendix A (45 *Fed. Reg.* 23723, April 4, 1980).

[9] Many utilities claim that the statement in the Notice of Proposed Rulemaking that the unquantifiable incremental costs normally recovered by percentage adders do not increase in proportion to escalating fuel costs is, to some extent, erroneous. While there may be merit in the argument that certain unspecified miscellaneous administrative costs have increased, the commenters supplied insufficient evidence to show that such costs have increased in proportion to the enormous increases in the cost of fuels since the oil embargo of 1973.

The Commission believes that percentage adders that recover revenues based wholly or in part on the purchased power price are no longer justifiable when permitted to recover revenues without limit. The Commission believes that a limit of one mill/kwh can usually be cost-justified. The final rule takes this fact into account by offering to accept, without cost justification, any percentage adder within that limit.

2. *The solutions presented by the final rule.*

The final rule addresses the problems discussed above by requiring that limits be placed on the amount of revenues that a utility may recover through percentage adders in rates used for transmission services in those circumstances where revenues recovered under these rates components are computed as a percentage of the purchased power price.

Of the comments filed in response to the Notice of Proposed Rulemaking, a few indicated approaches similar to the one adopted by the Commission in this rule.[10] A few utilities commented that the limitation on percentage adders might appropriately be applied only to transmission utilities to reduce unreasonable costs to the purchasing utility. This is, of course, the action taken in this rule. These commenters claim that intervening utilities in an interchange transaction perform only transmission services but impose substantial charges based on transmission plus generation costs.

The final rule is based on the determination that any adder that is applied in rates for transmission services and that computes revenues as a percentage of the purchased power price is unjust and unreasonable, unless the revenues recovered by such a rate component are limited and cost-justified. The Commission has determined that there is no logical connection between the costs of operation of the transmitting utility and the base to which percentage adders are generally applied, that is, the costs of the system or utility that first supplies the power. It is not justifiable that one utility's charges be predicated on another utility's costs. When percentage charges are added to the purchased power price of electricity by all intervening transmitting utilities during a multi-party interchange transaction, the rates and charges for the electric power paid by the ultimate purchaser reflect less and less the actual costs of producing and transmitting the electric power.

The final rule focuses on the most obvious excesses of recovery under percentage adders. It, in effect, establishes an administrative rule of convenience that permits a utility to establish an adder limited at one mill/kwh or less without submitting cost support information. This rule allows recovery under percentage adders of what the Commission believes is a reasonable amount of miscellaneous and unquantifiable incremental costs incurred for transmission services. Yet the rule does not necessarily require major changes in rate schedules or the collection and submittal of new data.

An example of a suitable amendment to a rate schedule under the final rule would be: "The percentage adder components contained in the transmission or third-party purchase and resale provisions of this rate schedule are hereby limited to recover no more than ——— mills per/kwh per transaction." This will indicate that revenues recovered by a transmitter or purchaser and reseller under a percentage adder based wholly or in part on the purchased power price will be limited to a specified amount in any transaction. Cost support will then be required only if the utility indicates revenues in excess of one mill/kwh.

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[10] Initial comments: Pacific Power & Light Company, at 9-10; Pennsylvania Power & Light Company, at 5-6, 10; Cities, at 14-15.

The Commission has a "heavy burden * * * to justify" departures from cost-based ratemaking.[11] It is the position of the Commission in this docket that, under existing circumstances, it is the unrestricted operation of percentage adders in rates for transmission services that constitutes a departure from cost-based ratemaking. Percentage charges have become less cost-based because of widely-recognized economic conditions that have escalated the incremental costs of producing electric power, especially the cost of fuel, and because the use of the percentage adder mechanism by transmitting utilities results in revenue recovery that bears little, if any, relation to the costs incurred by transmitting utilities. The Commission chooses to cure by rule this departure from cost-based ratemaking. In this rulemaking, the Commission is acting to prevent departures from established ratemaking concepts and to help ensure a correlation between charges for the electric power and the costs of producing it.

The Commission emphasizes that the approach taken in the final rule is predicated on the functional difficulties raised by the use of adders by transmitters in multiple, as opposed to bilateral, interchange transactions. The Commission continues to study the appropriateness of percentage adders when used for the primary generation of power and the interchange generation functions of transmitting utilities where the charge added to the overall charge for the power transmitted is based only on the internal incremental costs incurred by the transmitter. The Commission believes that limiting the presently unbridled operation of percentage adders in rates for transmission services will serve the public interest by helping to ensure that utilities recover under this component of a rate only incremental costs not recovered elsewhere.

3. *Effect of percentage adder limitations on interchange transactions.* Several commenters expressed concern that limitations on percentage adders might impede effective energy marketing through voluntary electrical interchange transactions in non-emergency situations. It was frequently observed that interconnected systems produce energy reliably and, generally, at a low cost to ratepayers. The Economic Regulatory Administration of the Department of Energy, because of its role in implementing national energy policy, allocating scarce fuel supplies, and promoting reliable bulk power system operations, was likewise concerned that interruptible transactions between non-contiguous utilities not be impeded during day-to-day operations.

The Commission acknowledges that voluntary negotiations and agreements for the interchange of electrical energy must be facilitated in emergency and non-emergency situations. When a utility experiences a fuel or capacity shortage, it must be able to shop for the best available source of electric power with the assurance that electric power can be purchased for its actual cost plus a reasonable incentive or fair rate of return. The reliability of interchange agreements are of increasing importance in the energy market. The continued occurrence of voluntary transactions will help avoid declarations of emergency under section 202(c) of the Federal Power Act.

The Commission does not believe that the proposed rulemaking in this docket would have destroyed the concept of power-pooling or vitiated the whole interchange system, as some commenters believed it might. The objectives of the Commission's actions in this docket have been focused on a specific rate problem, not reform of the whole interchange system. The final rule deals only with percentage adders in interchange rates for transmission services *if* the adders are based wholly or in part on the price of purchased power. Moreover, the rule will affect only rates for transmission or purchase and resale services and therefore addresses multiple party transactions, not bilateral system-to-system transactions where the power purchased remains within the receiving system. The final rule will not prevent full recovery of quantified incremental costs or of any fixed cost. Any incentives to engage in voluntary interchange energy marketing may be provided to transmitting utilities elsewhere in the rate structure, as should be the case.

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[11] *City of Chicago v. F.P.C.*, 458 F. 2d 731, 749 (D.C. Cir. 1971), *cert. denied*, 405 U.S. 1074 (1972). *City of Detroit v. F.P.C.* 230 F. 2d 810 (D.C. Cir. 1955), *cert. denied*, 352 U.S. 829 (1956).

Most commenters dealt with the merits of percentage adders, the bases and rationales of their operation, and the consequences of limiting recovery under percentage adders in terms of the incremental costs of generating utilities. The majority of the comments were not responsive to the concerns that form the predicate for the limitations on percentage adders in rates for transmission services provided in this rule, *i.e.*, the lack of connection between the adder charges and their cost base, and the multiplication of charges in multi-party transactions.

4. *Related reasons for Commission action.* The Commission bases its observations in part on the conclusions of the so-called "coal strike report" that shows how percentage adders operated in a fuel shortage emergency that resulted in many multiple interchange transactions.[12] Such adders have the same structure and they function similarly in non-emergency circumstances, although the frequency of multiple party transactions may be less in such circumstances.

Revenues collected under percentage adders increase as incremental costs rise. The average cost of oil-fired electrical generation rose from $0.70/mBtu at the beginning of 1973 to $2.08/mBtu in July 1978, with a peak of $2.30/mBtu in 1977.[13] A new round of increases in the cost of oil began in 1979. Since 1973, the increase in the cost of fuel has been greater than increases for any other component of out-of-pocket cost. This great rise in fuel costs has increased revenues recovered under adders that are described in rate schedules as a proportion of out-of-pocket or incremental costs.

The pattern of escalating costs is demonstrated by the increase in production expenses between 1969 and 1978. The average production expense, including fuel, was 4.2 mills/kwh in 1969; 6.7 mills/kwh in 1973; and 17.3 mills/kwh in 1978.[14] Production costs form the basis of a percentage adder. Average production expenses increased 60% between 1969 and 1973 and 158% between 1973 and 1978. A 10% adder based on such expenses would not have recovered as much as one mill/kwh until after the 1973 oil embargo when high fuel costs had already swollen production expenses.

The use of a ten or fifteen percent adder may have been an appropriate surrogate for quantification of incidental costs at a time when interchange transactions consistently delivered energy of 10 mills/kwh or less. However, such transactions may now involve the transfer of electricity at 50 mills/kwh or more, particularly when more than two systems are involved in the transaction. This increase, caused mainly by a rise in fuel prices, has tended to generate revenues under percentage adders that are inordinately large in relation to incremental out-of-pocket costs. Adders now recover significantly greater amounts of money—5 mills/kwh or more, in contrast to less than one mill in an earlier period.[15] This higher recovery of revenue exceeds increases in the kinds of incremental costs that percentage adders defray.

The coal strike report illustrates the relative magnitude of transactions that would be subject to the limitations on adders under the final rule. For example, during a one-hour period on February 18, 1978, the abnormally large interchange transactions being used to conserve coal ranged in capacity from a low of 19 megawatts (MW) for surplus power to 1200 MW for short-term power.[16] For a transmission or pass-through system, these transactions for a one-hour period would have produced a maximum revenue ranging from $19 to $1200 under a 1.0 mill/kwh adder.

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[12] report of the Designated Officer, *supra*, footnote 1.

[13] Id., Appendix I, at 9.

[14] U.S. Department of Energy Data Report, Statistics of Privately Owned Electric Utilities in the United States—1978: Classes A and B Companies (October 1979), at 40: *Production Expenses per Kilowatt-hour sold, mills—1978, 17.3; 1977, 15.9; 1976, 13.7; 1975, 12.7; 1974, 10.7; 1973, 6.7; 1972, 6.0; 1971, 5.5; 1970, 4.8; 1969, 4.2.*

The issues that the Commission faces are whether the use of percentage adders still works as a viable rule of administrative convenience and, if it does, what appropriate steps ought to be taken to restrain the inherent tendency of percentage adders to distort the cost relation of electric rates. The final rule adopted provides for cost-supported revenue limits that permit recovery of difficult-to-quantify out-of-pocket costs, such as billing and dispatching costs, and compensation for the cost of transmission losses in the event that such losses are not recovered separately in the incremental rate, as is sometimes the case.

The one mill/kwh limit beneath which cost support data are not required operates as a rule of administrative convenience, without requiring major renovation of rate schedules, to allow recovery of what the Commission anticipates to be all the unquantifiable incremental costs that transmitting utilities will usually incur. In establishing such a cut-off, the Commission confronts the same difficulties that a utility may confront in accounting for all its costs. The miscellaneous costs which are traditionally covered by percentage adders are precisely those costs that are too expensive or otherwise too difficult to quantify and recover under other components of the rate. The coal strike report and available information on the average costs of production, cited above, indicate that one mill/kwh or less has previously provided ample revenue to cover miscellaneous incremental costs. While these costs are no doubt subject to inflation, the 312% increase in average production costs in the decade between 1969 and 1978 is almost entirely due to escalating fuel costs.

Because the Commission is reasonably confident that one mill/kwh could almost always be cost-justified in terms of miscellaneous incremental costs, it has determined to accept any percentage adder limited to that amount or less without scrutinizing its cost basis. If more revenue is required to cover costs, the final rule permits a utility to show that a higher limit is justified. The Commission recognizes, of course, that there exists for any utility a point at which the increased size of any expenditure will warrant the effort necessary to quantify it and remove it from the domain of administrative conveniences like percentage adders.

The proposed one mill/kwh limitation on the adders used by transmitting utilities was believed by many of the commenters that addressed the subject to be sufficient to cover the utility's costs. One commenter, representing several municipalities, argued that less than one mill would suffice.[17] The Commission believes that the claim by transmitting facilities that they are entitled to a percentage adder based on the purchase price of interchange electric power does not conform to the precepts of cost-based ratemaking.

An issue raised by several commenters was the method by which the limitation proposed to be placed on percentage adders would be adjusted to reflect inflation in the costs of doing interchange business. A commenter proposed that the Commission adopt an adder that would recover a smaller

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[15] Id., Appendix I, at 12.

[16] Id. at 8.

[17] Oral comment of municipal utilities, Transcript of Public Hearing on Amendments to Parts 32 and 35, June 4, 1979, Washington, D.C. (Dockets Nos. RM79-28, RM79-29), at 100.

percentage of incremental costs or a fixed adder that would be updated annually. The Commission envisions periodic updating of the percentage adder level that, in the final rule, demarcates those adders that require cost justification from those that do not.

The prospect of further fuel price increases as well as other considerations make it imperative that the Commission's rate regulations do not discourage utilities from engaging in transfers of wholesale electricity from less expensive or more readily available sources by providing inadequate compensation for costs incurred in those transactions. However, it is also obligatory that costs to recipients of power in multiple interchange transactions bear a reasonable relationship to the costs required to produce and transmit the electricity. The coal strike report confirms that percentage adders tend to undermine the cost relation of electric rates, especially in multiple interchange transactions conducted during periods of escalating fuel costs.

5. *Commission authority to act.* Several commenters challenged the Commission's authority to establish rates by rulemaking procedures as proposed by the Commission in Docket Nos. RM79-28 and RM79-29. The Commission agrees with the position taken by the Commission staff in its reply comment in these dockets. Section 403(c) of the Department of Energy Organization Act (DOE Act) states that "any function * * * which relates to the establishment of rates and charges under the Federal Power Act * * * may be conducted by rulemaking procedures." Within the procedural safeguards in the DOE Act and section 553 of the Administrative Procedures Act that provide for full consideration of the issues and an opportunity for persons to present their views, the Commission is exercising its discretion to establish just and reasonable rates by rule.

While the Commission agrees with Potomac Electric Power Company (PEPCO) that section 403(c) does not provide the Commission ratemaking power greater than that afforded in sections 205 and 206 of the Federal Power Act, section 403(c) does establish a procedure for ascertaining the justness and reasonableness of rates on a generic basis, independently of strictly adjudicatory proceedings. Rulemaking is a particularly appropriate tool where a specific rate feature common to the rate structures of an entire industry is found to lead to undesirable effects or otherwise violate the accepted principles of ratemaking. The Commission's action in this docket addresses one feature of electric rates that has ceased to function equitably.

II. Finding

The Commission finds that rate components that recover revenues computed wholly or in part as a percentage of the price of purchased electric power are unjust and unreasonable if not limited and cost-justified as provided by this rule.

The Commission is exercising in this rulemaking its discretion to establish a just and reasonable rate pursuant to its authority under section 206(a) of the Federal Power Act.

III. Section-by-Section Analysis

Applicability (§ 35.23(a))

This paragraph states that the regulation applies to all electric rate schedules that are required to be filed under Part 35 of the regulations and that are used by utilities or systems that function as transmitters or purchasers and resellers of electric power in an electric interchange transaction.

Definition (§ 35.23(b))

This paragraph defines "purchased power price" as the amount paid by a transmitting utility for power generated by another utility.

General rule (§ 35.23(c))

This paragraph requires a utility to limit recovery of revenues under any rate component that computes those revenues wholly or in part as a percentage of the purchased power price. This component may be a so-called percentage adder. The limit will be established according to paragraph (d) in terms of mills per kilowatt-hour in any transaction.

Cost support information (§ 35.23(d))

This paragraph provides that a utility must submit cost support information to justify the limits imposed under paragraph (c). An exception to this requirement is provided in paragraph (e). The cost support information must be based on costs to the transmitting utility, other than the purchased power price, incurred during the transmission or purchase and resale function and not recovered in any other part of the rate.

Exception (§ 35.23(e))

If an adder will recover one mill per kilowatt-hour or less, no cost support information is required under paragraph (d).

Revision of rate schedules (§ 35.23(f))

This paragraph requires that any utility that is required under this section to place a limit on the amount of revenues recovered under percentage adders in a rate schedule or tariff, must amend such schedule or tariff to indicate that limit in accordance with this section not later than 60 days after the effective date of the rule. The utility is also required to cost-justify any limitation established for a percentage adder when filing any new rate or rate schedule change after this rule is effective, as provided in this section.

Effective date: This rule is effective June 11, 1980.

(Federal Power Act, as amended, 16 U.S.C. 792–828c; Department of Energy Organization Act, 42 U.S.C. 7101–7352; E.O. 12009, 3 CFR 142 (1978))

In consideration of the foregoing, the Commission amends part 35, Subchapter B of Chapter I, Title 18, Code of Federal Regulations, as set forth below.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,154]

45 F. R. 31980 (May 15, 1980)

18 CFR Part 282

[Docket No. RM80-24; Order No. 85]

Permanent Rule Defining Small Existing Industrial Boiler Fuel Users Exempt From Incremental Pricing Surcharges

Issued: May 8, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: Title II of the Natural Gas Policy Act of 1978 (NGPA), requires the Commission to prescribe and make effective a program of incremental pricing of natural gas used as industrial boiler fuel. Certain "small" industrial boiler fuel users, however, are required to be permanently exempted from incremental pricing by section 206(a)(2) of the NGPA, which directs the Commission to prescribe and make effective an exemption rule for such users by May 9, 1980.

The Federal Energy Regulatory Commission hereby adopts a rule which defines small existing industrial boiler fuel users and permanently exempts them from incremental pricing surcharges under the Natural Gas Policy Act of 1978.

EFFECTIVE DATE: Effective July 1, 1980, except that § 282.204 (governing filing of exemption affidavits) is effective May 8, 1980.

FOR FURTHER INFORMATION CONTACT:

Alice Fernandez, Office of Producer and Pipeline Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8095; or

Carol M. Lane, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8114.

SUPPLEMENTARY INFORMATION:

I. Introduction

Title II of the Natural Gas Policy Act of 1978 (NGPA), 15 U.S.C. §§ 3301 *et seq.*, requires the Commission to prescribe and make effective a program of incremental pricing of natural gas used as industrial boiler fuel. Certain "small" industrial boiler fuel users, however, are required to be permanently exempted from incremental pricing by section 206(a)(2) of the NGPA,[1] which directs the Commission to prescribe and make effective an exemption rule for such users by May 9, 1980.

In order to meet this statutory requirement, the Commission on March 6, 1980, issued a Notice of Proposed Rulemaking in the above docket (45 *Fed. Reg.* 15559, March 11, 1980) containing proposed regulations for a permanent exemption from incremental pricing for certain small industrial boiler fuel facilities.[2] The instant order discusses the public comments received in response to these proposed regulations and sets forth the regulations in final form to implement section 206(a)(2).

II. Background

A "small" industrial boiler fuel user is defined by section 206(a)(2)(B) as any industrial boiler fuel facility which was in existence on November 9, 1978, and which consumed in 1977 not more than an average specified volumetric level per day. The specified volumetric level is required to be established, using 1977 as a base year, by: (1) determining the average daily usage figure which would exempt only 5 percent of all gas transported by interstate pipelines and used as boiler fuel from incremental pricing surcharges; (2) comparing this figure to a figure of 300 thousand cubic feet (Mcf) per day; and (3) selecting the lower of these two figures as the threshold level for permanent exemption.[3]

Data collection and analysis by the Energy Information Administration, described in detail in the Notice of Proposed Rulemaking in this docket, indicated that the volume of interstate gas used by industrial facilities as boiler fuel during 1977, whose average daily use did not exceed 300 Mcf, constituted 2.7 percent, *i.e.*, less than 5 percent, of the total volume of such gas used in 1977. Based on this analysis, the Commission determined that the average daily volume which would exempt 5 percent of interstate boiler fuel use from incremental pricing would, in fact, exceed 300 Mcf per day. Accordingly, under the directive of section 206(a)(2), we proposed a rule which would provide a permanent exemption from incremental pricing for all industrial boiler fuel facilities in existence on November 9, 1978, whose average daily consumption in 1977 was 300 Mcf or less.

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[1] Section 206(a)(2) states in full:

(2) Permanent Exemption—

(A) General Rule—Not later than 18 months after the date of the enactment of this Act, the Commission shall prescribe and make effective a rule providing for the exemption of any small industrial boiler fuel facility from the rule required under section 201 (including any amendment under section 202 to such rule).

(B) Definition—For purposes of this paragraph, the term "small industrial boiler fuel facility" means any industrial boiler fuel facility in existence on the date of the enactment of this Act that had an average per day use of natural gas as a boiler fuel during the month of peak use during calendar year 1977 which did not exceed the lesser of—

(i) 300 Mcf; or

(ii) such average daily rate of use during a month of peak use as the Commission determines in such rule is necessary to assure that the volume of natural gas estimated by the Commision to have been used for boiler fuel during calendar year 1977 by facilities which are exempted under this paragraph does not exceed 5 percent of the total volume of natural gas estimated by the Commission to have been used for boiler fuel transported by interstate pipelines and used during calendar year 1977 as a boiler fuel.

[2] During the period prior to promulgation of a permanent rule, "small" users (defined as those using a monthly average of 300 Mcf or less per day in the year 1977) have been exempt from incremental pricing by operation of section 206(a)(1) and pursuant to § 282.203 of the Commission's regulations.

[3] In other words, the statute provides an exemption for that group of boiler fuel users whose 1977 operations, taken together, consumed not more than 5% of all interstate gas sold for boiler fuel use, *unless* such an exemption would result in a usage threshold greater than 300 Mcf per day.

The proposed regulations also set forth a definition of the term "in existence on November 9, 1978" for the purpose of determining which facilities qualify for an exemption under §282.203. A facility would meet this proposed definition if it were (1) technically capable of burning natural gas as a boiler fuel on November 9, 1978, and (2) substantially the same facility (when being reviewed pursuant to this rule) as it was during the month of peak usage in 1977.

Finally, the proposed rulemaking notice specifically sought public comment on the potential inequity resulting when current large users, as a result of deep curtailment in 1977, fall within the proposed "small" user definition and as such are permanently exempt from incremental pricing.

III. Summary of Public Comments

Forty-two companies, industry groups or public service commissions filed written comments in this docket. Representatives of a number of these organizations also testified in public hearings held in Washington, D.C on March 28, 1980, and in Los Angeles, California on March 31 and April 1, 1980. The great majority of commenters supported the Commission's proposals, their comments falling into four general areas.

A. *The 300 Mcf Per Day Threshold.* Section 206(a)(2)(B)(ii) requires that the Commission make a determination as to the necessity for a "5 percent rule" in lieu of the statutory alternative of a 300 Mcf per day threshold to determine the definition of "small" boiler fuel users. This Commission, however, has no capability for statistical data gathering, and we were therefore unable to undertake collection and analysis of the requisite data ourselves. We determined that the most reasonable means of obtaining such data was to request that the task be performed by the Energy Information Administration (EIA) which was created by Congress for the specific purpose of collecting and evaluating energy information.[4] EIA undertook the project in November, 1978, and transmitted its findings to the Commission 15 months later, on February 26, 1980.[5] EIA reported that they were:

> 99 percent confident that the volume of natural gas transported by interstate pipelines and used by small industrial facilities as a boiler fuel during calendar year 1977, whose average per day use during the month of peak use did not exceed 300,000 cubic feet, is less than 5 percent of the total volume of natural gas transported by interstate pipelines and used during calendar year 1977 as a boiler fuel.

Once having received these EIA findings, we viewed our function as primarily ministerial: we accepted the report and 10 days later issued the proposed rulemaking based on its contents.

No comments from the public challenged the accuracy of the EIA findings or the conclusions the Commission reached based upon them. To the contrary, there was general agreement among the commenters that the Commission's proposed rule adopting the 300 Mcf per day threshold on a permanent basis is a proper implementation of the statutory directive of section 206(a).

The Commission views its statutory burden under section 206(a) as a narrow one: we are required to define "small industrial boiler fuel facility" as a facility that had an average daily boiler fuel use not exceeding 300 Mcf, *unless* we determine that a rule setting a lower average daily rate of use:

> is necessary to assure that the volume of natural gas estimated by the Commission to have been used for boiler fuel during calendar year 1977 by facilities which are exempted under this paragraph does not exceed 5 percent of the total volume of natural gas estimated by the Commission to have been used for boiler fuel transported by

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[4] 42 U.S.C. § 7135.

[5] Energy Information Administration, U.S. Department of Energy, *Report to Determine 5 Percent Exemption to Incremental Pricing* (Memorandum from L. E. Moses to G. R. Hall, February 26, 1980).

interstate pipelines and used during calendar year 1977 as a boiler fuel.

Inasmuch as the EIA data suggests that the threshold should be kept at 300 Mcf per day, and since the Commission has no other basis upon which to make a finding that the 5% threshold falls below that figure, we are adopting the 300 Mcf per day threshold as required by the statute.

Some commenters suggested that the Commission adopt, in conjunction with the proposed rule, a further rule to exempt *all* industrial boiler fuel consumption below 300 Mcf per day, enabling industrial users not qualifying as "small" to be exempted from incremental pricing for their first 300 Mcf of daily usage. We believe this proposal is beyond the scope of the instant rulemaking. Congress was very specific in section 206(a) as to what constituted a "small" industrial boiler fuel user, and this rulemaking carries forth that specific statutory requirement. It does not extend to additional exemptions which would properly be considered under section 206(d).

Several commenters asserted that the Commission should reject the proposed rules in this docket and in Docket No. RM79-48,[6] and replace them with a rule which would permanently exempt the first 300 Mcf of gas consumed by each affected user's total nonexempt use. Under this proposal, all facilities (new or existing) and all industrial uses (boiler and non-boiler) would be exempt for the first 300 Mcf per day of usage, but *only* the first 300 Mcf. The Commission appreciates that this proposal has appeal from an administrative standpoint, since it would, *inter alia*, eliminate the necessity for determining whether a facility was "in existence" on the date of enactment and is "substantially the same facility" for purposes of incremental pricing. We note that a proposal based on the same principle was mentioned in the Notice of Proposed Rulemaking with respect to the issue of large users heavily curtailed in 1977. *See* page 11, *infra*.

After due consideration, however, the Commission has determined that section 206(a)(2) of the statute does not permit us to implement such a rule.[7] Under section 206(a)(2), once a facility has met the statutory definition of a "small industrial boiler fuel facility," the Commission is required to provide a permanent exemption for that facility itself, not just for a portion of that facility's use. Even if the facility should subsequently exceed the 300 Mcf per day threshold, the permanent exemption from incremental pricing would continue to apply under the statutory scheme. Accordingly, we decline to adopt the suggestion that all industrial facilities be made subject to a uniform rule exempting only the first 300 Mcf of daily usage.

B. *The Definition of "In Existence on November 9, 1978."* Several commenters expressed concern that the Commission's proposed definition of the statutory phrase "in existence on the date of the enactment of this Act" was overly broad and required clarification. We agree that such clarification would be helpful, and we have revised the definition along the lines suggested in several comments.

First, we have narrowed the concept in § 282.202(f)(1) of "installed capability" to use natural gas as a boiler fuel. That section has been revised to provide that an industrial boiler fuel facility, in order to qualify as "in existence on November 9, 1978," must have possessed the installed lines, piping, regulators, meters, and any other similar components necessary for that facility to have received and used natural gas on that date, as well as have possessed the installed capability to use natural gas as a boiler fuel on November

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[6] Docket No. RM79-48 proposes an exemption under section 206(d) for small industrial users who were not in existence on the day the NGPA was enacted.

[7] A rule adopting a portion of this suggestion is, however, being adopted pursuant to section 202. Under Docket No. RM80-10 (issued May 6, 1980) all non-boiler users are exempt from the first 300 Mcf per day of usage.

9, 1978. This revision makes it clear that a facility which could not have used natural gas in 1978 because it was not connected to a gas system is not eligible for classification as a small user under § 282.203. Any facility which came on line after date of enactment of the NGPA will have to establish eligibility for a small user exemption under the "new facilities" exemption proposed in Docket No. RM79-48.

Second, we have revised the proposed § 282.202(f)(2) in response to comments which asserted that a qualifying facility should be "substantially the same facility" as it was on November 9, 1978, not as it was at peak use in 1977. These comments pointed out that section 206(a)(2)(B) of the statute specifically ties the term "existing" to the date of enactment, while it ties volumetric consumption to the 1977 base period. Accordingly, it was asserted that the Commission must determine whether or not a facility was "in existence on the date of enactment" by considering the facility as of *that date*. We agree with this argument—and are amending § 282.202(f)(2) accordingly.

In addition, we are replacing the phrase "substantially the same facility," which commentors found ambiguous, with what we believe to be a clearer definition. Section 282.202(f)(2) is revised to require that a qualifying facility be "essentially the same facility as to burner input or boiler capacity" when it is being reviewed as it was on November 9, 1978.

C. *Large Users Heavily Curtailed in 1977.* In the Notice of Proposed Rulemaking, the Commission requested that commenters address the potential inequity presented by large industrial users whose deep curtailments in 1977 would enable them to qualify permanently as "small" users under the proposed regulations. The responses to this request fell into three groups: (1) those who asserted that the Commission has no statutory authority to alter the result; (2) those who agreed that the result was inequitable but could suggest no appropriate means of altering it; and (3) those who suggested various legal approaches to the problem. After a detailed study of all of these comments, the Commission has determined that it does possess the statutory authority to resolve this issue.

We note that section 206(a)(1)(B) of the statute defines a "small industrial boiler fuel facility" as a facility which, *inter alia*, "had an average per day use of natural gas as a boiler fuel during the month of peak use during calender year 1977 which did not exceed . . . 300 Mcf. . . ." The method to be applied in calculating this "average per day use" is not specified in the statute. The statute does, however, provide the Commission with express authority to define, by rule, accounting, technical, and trade terms used in the Act. *See* section 501(b). Pursuant to this authority, we are further amending § 282.202 by providing a definition of "average per day use of natural gas as a boiler fuel during the month of peak use during calendar year 1977." Such average shall be calculated by dividing the total boiler fuel use of natural gas in the month of peak use by the number of days of service at 100 percent of normal delivery level plus the number of days of service at less than 100 percent delivery level (computed by multiplying the number of days at each lesser level times the percentage of delivery level experienced on those days).

For example, assume that Facilities A, B and C each used 6000 Mcf of natural gas as boiler fuel in the peak month of 1977. Facility A experienced 100 percent of its normal delivery level for 30 days during that month. Facility B experienced 100 percent delivery level for 10 days but no service during 20 days. Facility C experienced 100 percent delivery level for 10 days and 50 percent of its normal level during 20 days. Under § 282.202(g), the average per day use for each of these facilities would be calculated as follows:

Facility A: 6000 Mcf divided by [30 days of service at 100 percent of normal delivery level] = 200 Mcf per day.

The facility qualifies for an exemption.

Facility B: 6000 Mcf divided by [10 days of service at 100 percent of normal delivery level, plus zero]=600 Mcf per day.

The facility does not qualify for an exemption.

Facility C: 6000 Mcf divided by [10 days of service at 100 percent of normal delivery level plus 20 days of service at 50 percent of normal delivery level] (6000 divided by 10+(20×.50)=300 Mcf per day).

The facility qualifies for an exemption.

The definition provided in § 282.202(g) is helpful in two ways. First, it clarifies the accounting method to be utilized in making the calculation of average daily usage. Second, it makes it less likely that a large user will be eligible to receive a permanent exemption from incremental pricing solely by virtue of curtailment in 1977.

D. *Miscellaneous Comments.* One commenter proposed that a blanket exemption from incremental pricing be provided for all industrial users, old or new, for the first 10,000 Mcf of use per month. Another proposed that the Commission provide a minimum two-year exemption for all companies which can demonstrate that they are displacing fuel oil with gas. We believe these proposals are beyond the scope of this rulemaking and decline to address them at this time.

IV. Affidavit Filings

The amendments adopted in this order make it necessary for all industrial end-users who believe they qualify for an exemption thereunder to file new exemption affidavits with both the Commission and their natural gas suppliers. The Commission is cognizant of the administrative burden thus imposed on industrial end-users but has not been able to devise a less burdensome approach, given the self-executing nature of the exemption affidavits under the incremental pricing program.

The affidavit filing procedures set forth in § 282.204 have been amended to incorporate the substantive amendments described above and to set forth new filing dates. In addition, the exemption affidavits used for the incremental pricing program have been revised to reflect the new regulations. The revised affidavits carry a date of "May 15, 1980" and will be available on that date from the Commission's Office of Congressional and Public Affairs, Division of Public Information.

As with the initial mailing of exemption affidavits, the Commission is requiring natural gas suppliers to supply a revised exemption affidavit to the owner or operator of each facility on the supplier's system which had previously been exempt as a small industrial boiler fuel facility. Industrial end-users are required to complete and return executed affidavits to the Commission, with a copy to their suppliers, on or before June 30, 1980, so that the facility may be permanently exempted from incremental pricing surcharges as of July 1, 1980.

V. Effective Date

Sections 282.202 and 282.203 are effective July 1, 1980. The Commission believes it appropriate to adopt this effective date in order to provide industrial end-users who may be affected by these rules the opportunity to become familiar with their provisions.

Section 282.204 is effective upon issuance. This section governs the mechanical procedures for obtaining an exemption from incremental pricing. It is necessary that revised exemption affidavits be distributed by suppliers to certain customers immediately in order that the latter may file for permanent exemptions by June 30, 1980. Accordingly, the Commission finds pursuant to section 553(d) of Title V of the United States Code, that good cause exists to make § 282.204 effective immediately.

(Natural Gas Policy Act of 1978, Pub. L. No. 95–621, 92 Stat. 3350, 15 U.S.C. § 3301, *et seq.*)

In consideration of the foregoing, Part 282 of Subchapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective as set forth above.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,155]

45 F. R. 31983 (May 15, 1980)

18 CFR Part 282

[Docket No. RM80-16; Order No. 86]

Disclosed Estimation Methodology Approach for Determination of Volumes of Natural Gas Used for Exempt Purposes Under the Incremental Pricing Program

Issued: May 8, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: On December 27, 1979, the Federal Energy Regulatory Commission (Commission) issued an interim rule which established procedures to be used for the first ten months of the incremental pricing program by industrial users in calculating the volumes of natural gas subject to incremental pricing surcharges (45 FR 21, January 2, 1980). The Commission hereby adopts a final rule in this docket which, in addition to other amendments described herein, extends the use of the estimating procedures for another year, *i.e.*, through October 31, 1981.

EFFECTIVE DATE: May 8, 1980.

FOR FURTHER INFORMATION CONTACT: Barbara Christin, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8079.

I. Background

On December 27, 1979, the Federal Energy Regulatory Commission (Commission) issued an interim rule which establishes procedures to be used for the first ten months of the incremental pricing program by industrial users in calculating the volumes of natural gas subject to incremental pricing surcharges (45 FR 21, January 2, 1980).

The interim rule added § 282.207 to Part 282 (Incremental Pricing) of the Commission's regulations. Section 282.207 provided that for the period January 1, 1980, to November 1, 1980, an industrial user may determine its exempt gas usage by estimates calculated in accordance with a disclosed estimation methodology formulated by the user. Industrial end-users then file monthly affidavits setting forth these estimates with their natural gas suppliers. In addition to the administrative aspects of the estimation methodology approach, § 282.207 contained provisions which govern how estimates shall be determined in certain situations.

Timely petitions for rehearing of the interim rule were filed by Phelps Dodge Corp. and Process Gas *et al.*[1] On February 21, 1980, the Commission issued an Order Granting Rehearing Solely for Purposes of Further Consideration. In that order, the Commission announced that it would consider the arguments raised in the applications for rehearing in the process of reviewing the comments filed on the interim rule and issuing final regulations. The issues raised in the petitions for rehearing are discussed below.

Public hearings on the interim regulations were held on March 28, 1980, in Washington, D.C. and on March 31 and April 1, 1980, in Los Angeles, California. The deadline for written comments was April 4, 1980. Thirty-five comments, including the petitions for rehearing, were filed by twenty-seven parties. (Several parties also filed supplemental comments.)

In the course of developing final regulations in this docket, the Commission has considered the written comments and the record developed at the public hearings. The final regulations promulgated herein reflect several changes made in response to many of the commenters' suggestions.

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[1] Joint petition for rehearing was filed by Process Gas Consumers Group, American Iron and Steel Institute, Georgia Industrial Gas Group, and Republic Steel Corp.

II. Summary of Comments and Revisions to Regulations

A. *Submetering Requirement.* As noted above, the interim regulations provided that the disclosed estimation methodology approach is to be used for the time period January 1, 1980, to November 1, 1980. Section 282.204(d)(6) of the Commission's incremental pricing regulations requires that, for the period after November 1, 1980, exempt usage shall be determined by meter readings based on submeters which the user must have installed or ordered by November 1, 1980.

All of the commenters who discussed the submetering requirement argued that it should be deleted from the regulations and that the Commission should permanently adopt the disclosed estimation methodology approach as the method to be employed by an industrial user in calculating its exempt use of natural gas for incremental pricing purposes.

The Commission is reluctant to rescind the submetering requirement at this time. The interim rule has only been in effect for four months, an inadequate period of time for the Commission to determine whether the approach would provide a sound regulatory mechanism on a long-term basis. In addition, a Phase II rule has been promulgated in Docket No. RM80-10 which expands the scope of the incremental pricing program to all industrial uses of natural gas. Because the Phase II rule is subject to Congressional review before becoming effective, the scope of the incremental pricing program is still uncertain.

The Commission notes, however, that the estimation methodology approach, thus far, appears to be workable. The Commission believes it would be appropriate at this time to extend the use of the estimating procedures for another year, in order to provide the Commission with adequate time to make a full assessment of the approach following establishment of the scope of the incremental pricing program. The Commission therefore, in addition to other amendments described below, amends the disclosed estimation methodology approach to provide for a one year extension, *i.e.*, through October 31, 1981.

B. *Treatment of Space Heat.* For purposes of the incremental pricing program, natural gas used for boiler fuel to raise steam for space heating by a non-exempt industrial facility is a non-exempt use of natural gas and is therefore subject to incremental pricing surcharges.

In the course of developing the interim regulations, however, the Commission became concerned about those facilities in which either a portion or most of the steam raised by gas is utilized for an exempt agricultural use, with only a small portion used for space heating within the facility. The Commission was of the belief that it would be administratively infeasible to require an agricultural user to measure separately its steam used for space heating in order to be billed a surcharge on that portion of its gas use. Furthermore, the Commission believed that in an agricultural facility, since some space heating "is most likely needed for product quality maintenance, the natural gas used to raise steam for such a purpose would qualify as an exempt use" (45 FR at 22).

As a result of this reasoning, a space heating proration formula for agricultural facilities was included in § 282.207(c)(1) of the interim regulations. That section provides that the natural gas used to raise steam which is used for space heating by an industrial facility is exempt from incremental pricing in the same proportion that the gas used as boiler fuel for other purposes is exempt. The effect of this provision is to allow an agricultural facility to prorate its entire steam usage among exempt and nonexempt products without being required to account for space heating usage.

Two written comments addressed the Commission's treatment of the natural gas used to raise steam for space heating purposes.

In comments filed by Northern Illinois Gas Company (Ni-Gas) it was argued that application of the space heating proration requirement may produce inequitable results in certain situations. Ni-Gas compared two agricultural facilities consuming natural gas as boiler fuel to raise steam. In the first facility, a portion of the steam is used in the manufacture of agricultural products and the balance is used for space heating purposes. In the second facility, all of the steam is used for space heating purposes. Under the provisions of § 282.207(c)(1), all of the gas used in the boiler by the first facility would be exempt from incremental pricing surcharges, while none of the gas consumed in the boiler by the second facility would be exempt. Ni-Gas recommended that the Commission amend its regulations to provide that the exempt volumes of natural gas used for space heating purposes be calculated by prorating according to the percentage of total production which is exempt.

Process Gas *et al.* (Process Gas) addressed the space heat formula in its petition for rehearing and in written comments filed with the Commission in this docket. Process Gas requested that the proration formula for space heating be modified to recognize that space heating "supports" non-boiler uses of gas as well as boiler uses. In other words, Process Gas argued that the space heating volumes of natural gas exempted from incremental pricing surcharges should be those volumes associated with end-uses such as process or feedstock use which are not subject to Phase I of the incremental pricing program as well as exempt boiler fuel usage.

Having given careful consideration to both comments, the Commission declines to adopt the proposed modifications. The Commission has determined that the administrative feasibility reason underlying the space heating proration formula remains the most compelling reason for continuation of the formula in the final rule. This determination, of course, does not preclude adjustment requests by parties under section 502(c) of the Natural Gas Policy Act of 1978 (NGPA) and § 1.41 of the Commission's regulations. Finally, § 282.207(c)(1) has been amended to clarify that the formula for prorating the gas used for space heating purposes is applicable only to situations involving facilities which consume gas in agricultural uses.

C. *Textile Operations.* Section 282.207(c)(2)(ii) requires that, in the case of textile mills which process or produce a product that is a combination of natural and synthetic fibers, the volume of natural gas which shall be exempt is limited to the portion of natural gas related to processing the natural fiber in the blend.

The American Textile Manufacturers Institute (ATMI) urged the Commission to delete the provision requiring apportionment of natural gas volumes used for processing natural fibers in blends. ATMI argued that one hundred percent of the volume of natural gas used in processing blended fibers is necessary to render the natural fiber portion into a useable form in the blends.

The Commission declines to adopt ATMI's recommendation. The Commission bases its determination on its interpretation of section 206(b)(3)(A) of the NGPA which limits the scope of an agricultural use exemption to the gas used in the production or processing of *natural fiber* only.

D. *Self-Help Supplies.* Section 282.207(c)(3) of the interim rule provided that, when the natural gas consumed by an industrial facility consists of utility-supplied gas and self-help supplies of natural gas which are commingled, the user's self-help gas supplies must be prorated among the various end-uses in the facility.

Ten commenters addressed the prorating requirement set forth in paragraph (c)(3) and recommended that it be modified. (Included in the ten commenters are the two parties which filed for rehearing of the interim rule.)

Several commenters recommended that, at the very least, the regulation relating to self-help supplies should be amended to allow for designations which can be supported by plant operating data. These commenters argued that the preamble to the interim rule and the interim regulations are inconsistent with respect to the self-help prorating requirement. While the preamble recognized that an industrial user may designate self-help supplies to certain non-exempt uses if such designation can be supported by plant operating data, § 282.207(c)(3) appeared to require a strict proration among all end-uses. The final regulations have been revised to make clear that self-help supplies may be designated to non-exempt end-uses, if the designations can be supported by plant operating data.

Process Gas and Phelps Dodge in their petitions for rehearing and several of the commenters argued that the industrial user should be given complete discretion to allocate self-help supplies to non-exempt end-uses. Other commenters advocated less discretion, stating that any designation to non-exempt uses should be consistent with either state or Federal law or regulations, applicable contracts between the buyer and the seller or transporter, or state tariffs.

There were a variety of reasons given in favor of user discretion. Some argued that to require proration was tantamount to burner tip regulation, as to which the Commission lacks jurisdiction for purposes other than incremental pricing. Others argued that a strict proration was inconsistent with other Commission programs relating to transportation of self-help supplies, such as the high-priority direct purchase program [2] and the fuel oil displacement program,[3] because under such programs volumes are transported for a designated end-use.

Ni-Gas, on the other hand, argued that in some cases, the user should not be allowed to allocate by prorating any self-help supplies to non-exempt uses. Ni-Gas was opposed to the proration requirement because, given the fact that the Commission can actually determine whether self-help gas, transported pursuant to Commission authorization, is for an exempt or non-exempt purpose, the formula in § 282.207(c)(3) resulted in an overstatement of exempt usage of utility-supplied gas.

The Commission had determined that it would be contrary to the objectives of the incremental pricing program to allow users complete discretion to designate volumes of self-help gas to non-exempt uses. However, there is merit to the argument that in some cases the purpose for which self-help supplies are purchased and transported can be determined.

The Commission has consistently recognized that ultimate destinations for delivered gas can be assumed even though not physically proven. In other words, access to gas supplies is sometimes conditioned upon designation of the gas for a specific end-use. For instance, gas transported pursuant to the Commission's fuel oil displacement program (Orders No. 30 and No. 30-A) can properly be designated for use as boiler fuel.

The prorating formula is therefore amended in the final regulations to recognize specific situations in which the prorating requirement does not apply and in which self-help supplies may be designated to specific end-uses.

1. *Commission Programs.* The final regulations provide that, where self-help supplies are transported pursuant to Commission authorization or certification, the volumes of self-help gas shall be deemed to be consumed in those end-uses which are consistent with the Commission program under which such gas is transported. Therefore, gas transported for essential agricultural and other high-priority uses under Subpart E of 18 CFR Part 157 of the Commission's regulations, and gas transported for process and feedstock

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[2] 18 CFR 2.79. FPC Orders Nos. 533, 533-A; FERC Orders Nos. 2, 2-A, and 52.

[3] 18 CFR Part 284 Subpart F. FERC Orders Nos. 30 and 30-A, issued May 17, 1979 and September 12, 1979, respectively.

requirements under the Commission's Order 533/Order 2 program [4] shall be deemed to be consumed for uses other than for boiler fuel. Volumes of gas transported under the fuel oil displacement program, on the other hand, are generally to be designated for use as boiler fuel.

2. *Contract between Buyer and Seller or Transporter.* Section § 282.207(c)(3)(ii) of the final regulations provides that, to the extent end-uses are designated in a contract which (1) is required to be filed with either the Commission or the appropriate state regulatory agency, and (2) has the legal effect of a tariff, such designations will be accepted for incremental pricing purposes.

3. *Plant Operating Data.* The regulations are amended as requested by several commenters to allow a designation of self-help volumes to non-exempt uses, but only if such designation is supported by plant operating data. Such a designation may be made only if it does not contradict designations required under a Commission program or a contract between buyer and seller or transporter which meets the requirements of § 282.207(c)(3)(ii).

4. *Prorating Requirements.* To the extent a user is unable to designate self-help supplies as prescribed above, the Commission's requirement for prorating of self-help supplies among all end-uses is retained.

E. *Miscellaneous.*

1. *Cogeneration.* One commenter, the American Paper Institute (API), recommended that the Commission modify its regulations so as to exempt all natural gas used in boilers if a cogeneration turbine capable of accepting all of the steam produced from natural gas is at the same site. API argued that this provision should be adopted in order to eliminate any incentive for companies to make expensive and unnecessary changes in steam distribution systems so as to put all steam generated for natural gas through cogeneration facilities.

If such an exemption were allowed, the mere presence of cogeneration equipment, regardless of fuel or operational status, would trigger an exemption for boiler fuel use of gas.[5] The extent of the exemption would depend solely on the capacity of the cogeneration turbine. The Commission does not favor exemptions for boiler fuel use of gas simply because a certain type of turbine exists nearby. The intent of the cogeneration exemption is to encourage cogeneration—not expensive steam distribution changes. An examination of the effect of the cogeneration exemption for existing cogeneration facilities may be a more reasonable regulatory response to API's comments than the liberalization of the estimation methodology suggested.

API also recommended that boiler fuel use of gas be exempted if it can be shown that the steam requirement would otherwise be met by steam extracted from a cogeneration turbine. If such a provision were adopted, a cogenerator could operate an extraction turbine in a fully condensing mode, while gaining an exemption for gas

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[4] Order No. 52, issued October 5, 1979, in Docket No. RM80-1 amends the regulations which implement the 533 program. While removing some of the end-use limitations previously incorporated in the program, the Commission nevertheless continues its policy of limiting volumes transported under an Order No. 533 certificate to a customer's process and feedstock requirements. Order No. 52 at page 7.

[5] The Commission further notes that cogeneration facilities, the installation of which began before March 13, 1980, need meet no efficiency standards in order to gain qualifying status. See Order No. 70, Docket No. RM79-54, March 13, 1980. New facilities burning no oil or gas also need not meet efficiency standards for qualification. Yet all facilities are required to meet efficiency standards in order to gain an exemption from incremental pricing. The efficiency standards for many facilities relate only to oil and gas use. Thus, exemption of boiler fuel gas used on the basis of proximity to cogeneration equipment might circumvent the Commission's concern with efficiency in granting exemptions.

Furthermore, specification of efficiency standards for facilities burning coal, biomass, or waste would not be an administratively simple task. Administrative problems would also undoubtedly arise over interpretations of what constitutes a common site for cogeneration activities and boiler fuel use of gas.

consumed in a boiler nearby. The Commission does not adopt this recommendation. Cogeneration facilities must produce power and useful heat or steam through sequential use of energy. Operation of a condensing turbine and a nearby process steam boiler is not cogeneration. An extraction turbine operated in a fully condensing mode cannot meet the efficieny and operating standards required for exemption from incremental pricing. An examination of the effect of the cogeneration exemption, especially as it relates to existing extraction turbine facilities, may be desirable at some point in the future.

2. *Filing Requirements.* A number of the commenters recommended revisions to the administrative aspects of the estimation procedures. The final regulations promulgated therein reflect the Commission's adoption of many of the suggestions.

The interim regulations in § 282.207(e) provided that all users who filed an estimation methodolgy were required to file a monthly affidavit setting forth the user's calculation of his exempt gas consumption. In response to recommendations by commenters, paragraph (e) is being revised in several respects.

A user is no longer required to file a monthly affidavit if either all of its exempt use or all of its non-exempt use is measured separately by a utility-owned meter. In addition, the final regulations provide that, for those users who are required to file a monthly affidavit, the affidavit may set forth either the exempt or non-exempt gas consumption. The final regulations also reflect an amendment which provides that the calculations contained in the monthly affidavit are based on the previous billing period and not the previous calendar month.

Finally, § 282.207(e)(3) of the interim rule required that the user submit the monthly affidavit within five business days from when the meter(s) is read by the utility. In response to several comments, two aspects of paragraph (e)(3) are amended in the final rule set forth below.

First, § 282.207(e)(3), as renumbered § 282.207(e)(1)(iii), allows a user and utility to agree to a time limit other than the five business days by which the monthly affidavit must be submitted. In the absence of an agreement between the user and the utility, the five business day deadline will apply. In addition, there has been some confusion over whether the monthly affidavit must be postmarked by the deadline or actually received by the utility. The final rule provides that the affidavit must be received by the utility by the applicable deadline.

3. *Record Retention.* Section 282.207(g)(1) of the interim rule required the natural gas supplier to retain for an indefinite period of time the monthly affidavits filed by industrial facilities. In response to a commenter's request, paragraph (g)(1) is amended in the final regulations by providing a time limit of three years for retention by the natural gas supplier of monthly affidavits.

III. Effective Date

The Commission finds good cause to make the regulations below effective immediately for the reasons that they reflect improvements in the disclosed estimation, methodology approach and that they in part recognize an exemption, relieve a restriction, or are interpretative in nature, which is consistent with section 553(d) of the Administrative Procedure Act.

The Commission Orders: For the reasons set forth above the Commission orders:

(A) The petitions for rehearing of the interim rule are granted to the extent indicated in the body of this order. To the extent not so granted, the petitions are denied.

(B) Effective immediately, Part 282 of Title 18 of the Code of Federal

Regulations in the table of sections for Part 282 and in §§ 282.204 and 282.504 as set forth in the interim rule in this docket are made final with further changes as set forth below.

(C) Effective immediately, § 282.207 of Part 282, Title 18 of the Code of Federal Regulations is revised and made final to read as set forth below.

(Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, 15 U.S.C. 3301, *et seq.*)

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,156]

45 F. R. 31300 (May 13, 1980)

18 CFR Part 282

[Order No. 81; Docket No. RM79-21]

Rule Further Exempting Industrial Boiler Fuel Facilities From Incremental Pricing Above the Price of No. 6 Fuel Oil and Applying Ceiling Prices to Forty-Eight Incremental Pricing Regions

[illegible]ay 7, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule, subject to Congressional review.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts a rule which, if not disapproved by either House of Congress, will provide that large industrial boiler fuel facilities subject to the incremental pricing program will continue to be surcharged only at the level of the high sulfur No. 6 fuel oil price until October 31, 1981.

EFFECTIVE DATE: July 1, 1980, or such later date as represents the first day following 30 days of continuous session of the Congress, if not disapproved by either House.

FOR FURTHER INFORMATION CONTACT: Alice Fernandez, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357-9095.

I. Introduction

Title II of the Natural Gas Policy Act of 1978 (NGPA), 15 U.S.C. 3301 *et. seq.*, establishes an incremental pricing program for pricing natural gas. Section 201 of Title II requires that natural gas acquisition costs subject to the incremental pricing program are to be passed through to certain industrial boiler fuel facilities by means of incremental pricing surcharges. Section 204 provides, however, that surcharges to incrementally-priced industrial facilities should not be so high as to cause the rates charged for natural gas to exceed the price of the alternative fuel for such facilities. In a previously issued order, the Commission adopted a three-tier system of alternative fuel price ceilings.[1] Under this system prices for No. 2 fuel oil, low-sulfur No. 6 fuel oil and high-sulfur No. 6 fuel oil are to be published for industrial boiler fuel users within each incremental pricing region. The price ceiling applicable to each industrial boiler fuel user is the ceiling price which corresponds to the lowest priced fuel oil that the facility has the installed capability and legal authority to burn.

Pursuant to Commission authority under section 206(d) to adopt exemptions from the incremental pricing program, the Commission hereby adopts and transmits to Congress a rule affecting the alternative price ceiling applicable to industrial boiler fuel facilities subject to incremental pricing. This rule provides that until November 1, 1981, incrementally priced industrial boiler fuel facilities shall be exempt from incremental pricing above the price level for high-sulfur No. 6 fuel oil. This rule also provides that until October 31, 1981, the incremental pricing regions for industrial boiler fuel users will correspond to the 48 contiguous states.

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[1] *Regulations Implementing Alternative Fuel Cost Ceilings on Incremental Pricing under the Natural Gas Policy Act of 1978*, Order No. 50, Docket No. RM79-21, "Final Rule", issued September 28, 1979, 44 FR 57754 *et. seq.* (October 5, 1979).

Under section 206(d)(2) exemptions from incremental pricing regulations must be sent to the Congress for review. If neither House of Congress disapproves the rule within a 30-day period of continuous session, the exemption rule becomes effective. This section 206(d) exemption rule relating to alternate fuel prices follows a similar rule that was transmitted to the Congress in October of 1979. The first section 206(d) rule sent to the Congress deferred application of the three-tier system of alternative price ceilings until November 1, 1980.[2] Neither House disapproved the first exemption rule, and it became effective December 1, 1979. As stated, this exemption rule extends application of a single-tier, high-sulfur No. 6 ceiling for an additional year.

II. Background

The incremental pricing provisions of Title II of the NGPA were enacted by the Congress for the purpose of placing certain portions of an interstate pipeline's acquisition costs of natural gas into a special incremental pricing account for passthrough to incrementally priced users. The NGPA specifies that the incremental pricing program shall be applied in two phases. In the first phase (Phase I) incremental pricing is applied to large industrial boiler fuel facilities that use natural gas as a boiler fuel.[3] In the second phase (Phase II) incremental pricing may be extended to a larger class of industrial users than those affected by Phase I. The Phase II rule is being issued concurrently with this rule and, under section 202(c) of the NGPA, will be subject to Congressional review.

For industrial facilities subject to either the Phase I or the Phase II rule, section 204(e) provides that the passthrough or surcharge should not rise above the "appropriate alternative fuel cost" for the region where the facility is located. The appropriate alternative fuel cost is the price paid for No. 2 fuel oil in the region where the industrial facility is located, unless the Commission determines that a No. 2 fuel oil alternative fuel cost would cause the loss of industrial load and an increase in rates to residential and commercial gas users (high-priority gas users). In such cases, it may reduce the alternative fuel ceiling to a level not lower than the price of No. 6 fuel oil. Section 204(e) provides:

> Sec 204 Method of passthrough.
>
> * * * * *
>
> (e) Determination of alternative fuel cost.
>
> (1) In general.—Except as provided in paragraph (2), the appropriate alternative fuel cost for any region (as designated by the Commission) shall be the price, per million Btu's, for Number 2 fuel oil determined by the Commission to be paid in such region by industrial users of such fuel.
>
> (2) Reduction of Appropriate Alternative Fuel Cost Allowed.—The Commission may, by rule or order, reduce the appropriate alternative fuel cost—
>
> (A) for any category of incrementally-priced industrial facilities subject to the rule required under section 201 (including any amendment under section 202 to such rule) located within any region and served by the same interstate pipeline; or
>
> (B) for any specific incrementally-priced industrial facility which is subject to such requirements and which is located in any region;
>
> to an amount not lower than the price, per million Btu's, for Number 6 fuel oil determined by the Commission to be paid in such region by industrial users of such fuel, if and to the extent the Commission determines, after an opportunity for written and oral presentation of views, data, and arguments, that such reduction is necessary to prevent

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[2] *Rule Exempting Industrial Boiler Fuel Facilities from Incremental Pricing Above the Price of No. 6 Fuel Oil*, Order No. 51, Docket No. RM79-21, issued September 28, 1979, 44 Fed. Reg. 57778 (October 5, 1979).

[3] The mechanism for incremental pricing in accordance with section 201 is set forth in *Regulations Implementing the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978*, Docket No. RM79-14, Order No. 49, "Final Rule", issued September 28, 1979, 44 Fed. Reg. 57726 (October 5, 1979).

increases in the rates and charges to residential, small commercial, and other high-priority users of natural gas which would result from a reallocation of costs caused by the conversion of such industrial facility or facilities from natural gas to other fuels, which conversion is likely to occur if the level of the appropriate alternative fuel cost were not so reduced.

A. Commission Order No. 50

The Commission's choice of a three-tier system of alternative fuel prices for Phase I was based upon a determination that the appropriate alternative fuel cost should be designed to achieve the maximum possible flow-through of incremental costs to industrial boiler fuel users without causing load loss that would result in shifting capital costs to high-priority users not subject to incremental pricing. The Commission's order adopting a three-tier ceiling (Order No. 50) reasoned on the basis of the data presented that a large number of price-sensitive industrial boiler fuel users with capability to burn fuel oils cheaper than No. 2 would switch to alternate fuels if a single-tier No. 2 ceiling were adopted. The Commission further determined that, because of the projected substantial load loss at a No. 2 ceiling, there would likely be a disadvantageous shifting of capital costs to high-priority users.

The Commission also concluded, however, that Congress did not intend that the alternative fuel ceiling be reduced to the price level of No. 6 fuel oil if such a ceiling would likely result in rates to high-priority users that are higher than they would be at a No. 2 ceiling. Data submitted by the Department of Energy and widely supported by other commenters convinced the Commission that in contrast to either a No. 2 or a No. 6 ceiling, a three-tier ceiling results consistently in lower rates to high-priority users. Also, a three-tier system applying separate prices to high-sulfur No. 6 and low-sulfur No. 6 fuel oil recognized the difference in sulfur content of No. 6 fuel oil.

The Commission also explained in Order No. 50 that a three-tier ceiling would be consistent with the national goal of displacing imported oil with domestic gas resources. A single-tier, No. 2 ceiling would have caused price-sensitive industrial boiler fuel users possessing alternative fuel capability to switch to use of oil. The Commission reasoned, however, that the economic loss could be avoided by use of a three-tier system that would minimize load loss.

Another feature of the choice of a three-tier system of alternative price ceilings was the Commission's decision, expressed in Order No. 50, to require that incremental pricing ceilings be established for each of the 48 contiguous States and 31 selected metropolitan regions. The Commission concluded that together the 79 incremental pricing regions would reflect fuel oil market conditions in discrete marketing areas while also recognizing State boundaries.

Until October 20, 1980, Order No. 50 provides that ceilings should be published for only the 48 contiguous States. The decision to initially limit the number of regions to the 48 States was based on the difficulty anticipated by the Energy Information Administration in developing ceilings for the metropolitan regions. Order 50 requires that EIA assume responsibility for collecting price data and publishing, on or before the twentieth of each month, the price ceilings to be applied in the subsequent month. It was expected that the delay in publication of price ceilings for the 31 metropolitan regions until October 20, 1980, would enable EIA to perfect its system for deriving price ceilings for each of the metropolitan regions identified in Order No. 50.

B. Commission Order No. 51

Order No. 51 was issued by the Commission as a companion rule to Order No. 50. Order No. 51, issued under authority of section 206(d) of the NGPA, amended Order No. 50 to provide that for the period January 1, 1980 until November 1, 1980, a single-tier high-sulfur No. 6 alternative fuel ceiling would be applied to industrial boiler fuel facilities subject to incremental pricing. Order No. 51 thus provided an exemption from the regulations adopting a three-tier system of alternative fuel prices.

The decision to postpone implementation of the upper two ceilings until November 1, 1980, resulted from the Commission's concern that additional familiarity with the program was needed before the three-tier system was applied. More specifically, the Commission expressed its concern that a three-tier system might induce significant investment in No. 6 oil burning capability solely for the purpose of qualifying for the lower incremental pricing ceiling. The Commission acknowledged that the level of such "induced investment" could not be estimated with precision at that time, although the record indicated that the amount could be sizable. During the period of application of a single-tier system, the Commission concluded it would be able to gain a better understanding of the number and characteristics of incrementally priced facilities and the price relationships among the various alternative fuels. Such additional knowledge could then be utilized by the Commission to analyze and evaluate the amount of induced investment and the implications for the economic interest of high priority gas consumers as well as fuel oil consumers.

The Commission further explained that postponement of the three-tier system of ceiling prices would likely ease implementation of the incremental pricing program. As compared to a single-tier ceiling, a three-tier system of prices necessarily requires application of more complex regulations, a more extensive enforcement program to assure compliance with the regulations and a more complicated data gathering and analysis effort to derive three separate prices for each incremental pricing region.

Especially critical to the Commission at the time it adopted Order No. 51 was the concern that data collection should be reliable and not result in inaccurate price ceilings. Inaccuracy could result in load loss of industrial boiler fuel users and a shift of capital costs to high priority users. The Commission therefore determined that to avoid such consequences and enhance the likelihood of statistically valid results, application of the three-tier system of alternative fuel price ceilings should be postponed until November 1, 1980.

In accordance with section 206(d) of the NGPA, the exemption set forth in Order No. 51 was sent to the Congress on October 10, 1979 for its review. Neither House of Congress disapproved the Order No. 51 exemption within the statutorily-prescribed period of 30 calendar days of continuous session of Congress and, accordingly, the exemption rule became effective.

III. Further Exemption From a Three-Tier Ceiling

The Commission has determined to amend the regulations to provide that, for the period January 1, 1980, until November 1, 1981, an incrementally-priced industrial boiler fuel facility shall be exempt from incremental pricing above the price level of high-sulfur No. 6 fuel oil in the incremental pricing region in which the facility is located. This exemption rule, like the previous rule set forth in Order No. 51, will be transmitted to the Congress.

This rule is subject to Congressional review and may be disapproved upon the resolution of either House of Congress. If, however, the exemption embodied in this rule is not disapproved during the first 30 days of continuous session following submittal of the rule to Congress, the rule will take effect on July 1, 1980, or such later date as represents the first day following 30 days of continuous session of Congress.

If not disapproved by either House of Congress, this exemption will postpone application of the low-sulfur No. 6 and No. 2 alternative price ceilings until November 1, 1981. The price for high-sulfur No. 6 fuel oil will thus be the only published alternative fuel price ceiling in each incremental pricing region. This exemption will expire, however, on October 31, 1981. On November 1, 1981, the three-tier system of alternative price ceilings will become effective, unless the rule establishing the three-tier system is amended or a further exemption rule is transmitted to Congress and not disapproved.

It is the Commission's conclusion that further experience with the incremental pricing program is necessary before a three-tier system of price ceilings is placed in effect. At this time, the Commission does not possess adequate information about the level of investment in No. 6 oil burning capability that may be induced as a result of application of a three-tier ceiling. Further, the Commission is concerned about the current status of data collection and analysis necessary to apply a three-tier system of price ceilings.

The first exemption rule transmitted to Congress expressed the concern that a three-tier system might lead to significant and possibly unproductive investment for equipment to burn high-sulfur No. 6 fuel oil. It was anticipated that abeyance of the three-tier system of prices until November 1, 1980, would provide the Commission adequate time to gain familiarity with the incremental pricing program as well as the number of industrial boiler fuel facilities incrementally priced and the consequent extent to which induced investment would likely occur. The Commission's anticipation now appears to have been somewhat optimistic.

The Commission's own experience with the incremental pricing program has not yet provided the familiarity and knowledge necessary to confidently predict the amount of induced investment that would occur under a three-tier ceiling. Several matters concerning the scope and application of Phase I are only now being resolved.[4] Others will be resolved in the near future.[5] The Commission expects that resolution of many of the outstanding issues will provide information to assist the Commission in determining the scope of induced investment that might occur under a three-tier system of price ceilings. Time will be needed, however, to evaluate such forthcoming information and, in the interim, the Commission judges that abeyance of the three-tier ceiling best serves the public interest.

Moreover, industrial users of gas have also expressed a belief that postponement of the application of the three-tier ceiling is necessary. For example, many commenters have indicated in their comments relating to issues in Phase II that unfamiliarity about the effect of incremental pricing upon induced investment continues to exist. Such comments reinforce the Commission's view that this exemption rule is necessary.

Postponement of the three-tier ceiling approach is also necessitated by the Commission's concern that ceiling prices be accurate. One of the reasons given by the Commission for the initial delay in applying a three-tier system of prices was that a single-tier ceiling applied until November 1, 1980, would ease the burden of providing accurate price ceilings. The experience with a single price ceiling for the first several months of the incremental pricing program demonstrates that the task of establishing accurate price ceilings is challenging.

The experience with the April price ceilings is indicative of the ongoing efforts of the Commission and EIA to assure accuracy of the ceiling prices.[6] The Commission cannot state with certainty, however, that an acceptably high degree of accuracy can be assured by November 1, 1980 for a three-tier system of ceiling prices. To resolve uncertainties about the ability of EIA to implement the three-tier ceiling approach, the Commission is convinced that a further delay of the three-tier system is necessary. Abeyance of the first two tiers for an additional year until November 1, 1981, should serve to resolve uncertainties about the ability to implement an accurate three-tier ceiling.

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[4] *See e.g., Permanent Rule Defining Small Existing Industrial Boiler Fuel Users Exempt from Incremental Pricing under the Natural Gas Policy Act of 1978,* Docket No. RM80-24, "Final Regulations" issued today.

[5] *See e.g., Treatment Under the Incremental Pricing Program of Natural Gas Used as Boiler Fuel to Raise Steam which Forms an Integral Step in the Manufacturing Process for Fertilizer,* Docket No. RM80-18, "Notice of Opportunity to Comment on Whether a Rulemaking Proceeding Should be Established", issued February 21, 1980, 45, Fed. Reg 13122, (February 28, 1980).

[6] *Rule Adopting Revised Alternative Fuel Price Ceilings for the Month of April 1980,* Docket No. RM80-46, "Interim Rule", issued March 28, 1980, 45 Fed. Reg. 22891 (April 4, 1980).

IV. Incremental Pricing Regions

The preamble to the rule set forth in Order No. 50 provides that until October 20, 1980, there will be 48 incremental pricing regions that correspond to each of the 48 contiguous states. Thereafter, the preamble provides that incremental pricing ceilings will be developed for 79 regions corresponding to the 48 states and 31 metropolitan regions.

The Commission concludes that an additional year's experience with incremental pricing should be acquired before the program is expanded to the 79 incremental pricing regions. EIA continues to experience difficulty in developing a method for determining ceilings for the metropolitan regions. In keeping with its intent to assure accurate ceiling prices, the Commission will therefore delay publication of ceiling prices for the 31 metropolitan regions. It is expected that such delay will allow EIA to perfect a system for developing ceiling prices for metropolitan regions.

V. Public Procedures and Effective Date

Section 502(b) of the NGPA requires that "[t]o the maximum extent practicable", an opportunity for the oral presentation of data, views, and arguments be afforded for certain regulations under the NGPA. The Commission's actions reflected in this order are based upon comments previously received by it in this docket, as well as comments received with respect to other aspects of the Commission's own administrative experience with the incremental pricing program.[7] In such circumstances, the Commission finds that good cause exists to have dispensed with additional notice and comment procedures. To request further comments at this time upon the issues resolved by this order would result in needless delay and replication of an already developed record.

(Natural Gas Policy Act of 1978, Pub. L. 96-621, 92 Stat. 3350, 15 U.S.C. 3301, *et seq.*)

In consideration of the foregoing, if neither House of Congress passes a Resolution of Disapproval of the regulations transmitted to them in this order, Title 18 of the Code of Federal Regulations is amended in Part 282 to read as set forth below, effective July 1, 1980, or such later date as represents the first day following 30 days of continuous session of Congress, as described in section 507(c)(3) of the NGPA.

By the Commission.

Kenneth F. Plumb,
Secretary.

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[7] *See e.g.*, comments filed in *Rule Required Under Section 202 of the Natural Gas Policy Act of 1978*, Docket No. RM80-10: and, *Permanent Rule Defining Small Existing Industrial Boiler Fuel Users Exempt from Incremental Pricing Under the Natural Gas Policy Act of 1978*, Docket No. RM80-24.

[¶ 30,157]

45 F. R. 31622 (May 13, 1980)

[Note: These rules have been revoked. See ¶ 30,182.]

18 CFR Part 282

[Docket No. RM80-10]

Rule Required Under Section 202 of the Natural Gas Policy Act; Incremental Pricing

May 6, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule, subject to Congressional review.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts regulations in accord with the directive

of section 202 of the Natural Gas Policy Act of 1978 (NGPA). The rule is subject to Congressional review and will not become effective if disapproved by either House of Congress. If not disapproved, the rule will expand the scope of the incremental pricing program to all industrial end-users not exempt under the NGPA, and provide that those users of natural gas other than as boiler fuel be permanently subject to incremental pricing surcharges up to the price of high-sulfur No. 6 fuel oil.

EFFECTIVE DATE: Such date as represents the ninetieth day following expiration of 30-day Congressional review period, if not disapproved by either House.

FOR FURTHER INFORMATION CONTACT: Alice Fernandez, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 (202) 357-9095.

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I. Introduction

Title II of the Natural Gas Policy Act of 1978 (NGPA) (Pub. L. 95-621) requires that the Federal Energy Regulatory Commission (the Commission) promulgate regulations to channel a specified portion of the increasing cost of natural gas to industrial users. The "incremental costs" of natural gas are to be passed through from interstate pipelines to industrial end users by means of a surcharge pricing mechanism.

Under Title II of the NGPA, the incremental pricing program is to be implemented in two phases. The first phase was implemented by regulations issued by the Commission on September 28, 1979 (44 FR 57726, October 5, 1979).[1] Under those regulations, only large industrial facilities that use natural gas as a boiler fuel are subject to incremental pricing.

Section 202 of Title II requires the Commission to promulgate a second phase (Phase II) rule by May 9, 1980, that amends the scope of the incremental pricing program to include other industrial users. Specifically, subsection (b) of section 202 provides that the second phase rule:

> Shall apply with respect to the industrial use of natural gas (as defined by the Commission in such rule), including boiler fuel use of natural gas . . . by—
>
> (1) Any industrial boiler fuel facility . . . and
>
> (2) Any industrial facility which is within a category defined by the Commission in such amendment as subject thereunder to the requirements of such rule which is not exempt under section 206.

Section 202 also directs the Commission to submit Phase II rule to Congress, which has reserved the right to review and disapprove this rule if it decides against extending the scope of the incremental pricing program.

On November 15, 1979, the Commission issued a Notice of Proposed Rulemaking providing for a broad Phase II expansion of the incremental pricing program.[2] This proposal derived from the Commission's review of the Congress' dual objectives in enacting the incremental pricing provisions. One objective is to prepare the natural gas market for deregulation in 1985. The second objective is to provide a measure of shelter to residential and other high priority customers from rising gas prices. The Commission then gave its preliminary view that "the Congressional purposes underlying incremental pricing would be most fully met if all industrial users, other than those specificallly excluded by statute, are brought within the scope of Title II." (mimeo, p. 5)

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[1] The regulations issued on September 28 were contained in two dockets. Docket Nos. RM79-14 and RM79-21.

[2] Docket No. RM80-10: 44 FR 67170 (November 23, 1979).

In the Phase II Notice, the Commission also proposed to apply the "three-tier" system for determining the alternative fuel ceiling, which was developed for Phase I, to Phase II as well. In addition, the surcharge or flow-through mechanism developed for Phase I was proposed for Phase II. The Commission sought to comment on these basic features as well as on several subsidiary aspects of its Phase II proposal.

Public hearings were held on the Phase II proposal in San Francisco, Salt Lake City, Chicago, Louisville and Washington, D.C. during the month of January; nearly 400 written comments were received.[3] Many fundamental questions were raised regarding both the specific features of the Commission's Phase II proposal and the ability of the overall incremental pricing program to fulfill its objectives. Those comments have played a major role in helping the Commission shape its Phase II submission to Congress. The final rule prescribed below responds in various ways to data, views, comments and criticisms of the rule proposed in the Commission's November 1979 Notice.

At the outset, the Commission wishes to point out that many comments suggested that it not develop any expansion of the program beyond what is already required by section 201 (Phase I). It was argued that the Congressional purposes underlying incremental pricing are misguided or that market conditions have so changed as to render the program inappropriate. The Commission does not accept this suggestion. The Commission believes that it was neither requested nor authorized to second-guess the social and economic judgments that the Congress made in enacting Title II. The role of the Commission under Section 202 is more limited. Instead, the Commission is instructed to bring its technical expertise to bear on the design of a workable Phase II rule that can best advance the purposes set by the Congress. It is up to the Congress to decide whether this Phase II submittal meets adequately the social and economic goals of the incremental pricing program or, indeed, whether those goals are still appropriate.

By virtue of the very review procedures built into section 202, it seems clear that the Congress sought to have this Commission develop a meaningful Phase II rule. The Congress would not have a meaningful choice if the Commission were to offer no rule, or a very narrow rule, for its review. The Congress has reserved to itself the fundamental judgment as to whether an expansion of incremental pricing is consistent with current national priorities.

The Commission believes that this Phase II rule presents a meaningful choice to the Congress. It proposes to broaden the scope of the incremental pricing program. On the other hand, it responds to the substantial body of comments that have urged the Commission to take a careful approach to Phase II and its attendant economic impacts.

II. Summary of the Phase II Submittal

The Phase II rule approved by the Commission and submitted to the Congress would extend the incremental pricing program to all industrial users except those exempted specifically by the statute and would apply to all industrial gas consumption exceeding 300 Mcf per day. It also sets a uniform price ceiling for natural gas sold to industrial users at the price of No. 6 high-sulfur residual fuel oil.

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[3] A full list of commenters is contained at Appendix A.

An essential feature of the Phase II rule is that non-boiler fuel industrial users will be subject to incremental pricing only with respect to levels of consumption exceeding 300 Mcf per day. Thus, a facility using 400 Mcf per day of Phase II (non-boiler) uses would have 100 Mcf per day subject to incremental surcharges. For an industrial facility using 380 Mcf per day of natural gas as boiler fuel (a Phase I user), the entire 380 Mcf per day is surcharged, pursuant to the statutory provisions for incremental pricing of boiler fuel.

Another feature of the Phase II rule is that it would give States discretion to limit the impact of Phase II on individual users in order to ease any serious transitional burden. If, during the first year, Phase II would result in a surcharge of more than 75 cents per Mcf to any user, the State regulating consumption of that gas may allocate that portion of the surcharge exceeding 75 cents to other incrementally priced gas users within the State.

Technically, the Phase II submission would apply to all industrial "uses" other than those specifically exempted by statute. Gas straddle plants, which extract liquids from the gas stream, would be covered only with respect to net "use", or consumption, of gas as a fuel.

The Commission also recommends to Congress that the three-tier alternative fuel price ceiling approach under Phase I be postponed another year, until November 1, 1981. This specific action is submitted to the Congress for review pursuant to the general exemption authority of section 206(d). If the Congress agrees to this one-year exemption from higher prices for Phase I users, all users under both Phases I and II will have the same No. 6 high sulfur fuel oil ceiling through October 1981.

By the end of 1983, the Commission will review the impact of the incremental pricing program and evaluate what, if any, further changes would best advance the purposes of the program. The results of this review will be reported to Congress.

The final Phase II rule promulgated here will be submitted to the Congress by May 9. Either House has the statutory authority to veto the submission during the subsequent 30-day review period. If not disapproved, the Phase II expansion of the incremental pricing program will take effect 90 days after the Congressional review period has ended.

III. Background of the Incremental Pricing Program

The NGPA was enacted in 1978 to reform regulation of the natural gas industry and provide for phased deregulation of new natural gas. Title I of the NGPA establishes incentive price schedules for variously defined categories of gas. Title I replaced a system of cost-based rates under the Natural Gas Act of 1938, which reached only to sales of gas in interstate commerce. The wellhead price of natural gas produced and consumed in the same state (so-called intrastate gas) was not subject to the Natural Gas Act. The NGPA changed the system dramatically by setting higher wellhead prices than has previously been allowed, and by also extending Federal price controls to previously unregulated intrastate sales. The maximum lawful prices set by Congress were substantially in excess of then-prevailing cost-based nationwide rates that had been set by the Federal Power Commission as regulated price ceilings.

Under Title I, the price of "new" natural gas will be deregulated on January 1, 1985. New natural gas is defined as production from wells spudded (drilling commenced) on or after February 19, 1977, which are more than 2½ miles from or 1000 feet deeper than the nearest old well. In addition, production from new development wells will be deregulated by 1987. Finally, NGPA price controls on most flowing intrastate gas will expire on January 1, 1985.

A. Objectives of Title II Incremental Pricing. Title II of the NGPA, the incremental pricing provisions, were included by the Congress for two reasons. First, incremental pricing is designed to mitigate any disruption of the natural gas market that might occur upon deregulation in 1985. Many members of Congress, particularly those opposing sudden deregulation, feared serious disruption if deregulation were to occur during a period of supply and demand imbalance. The relatively low price of gas remaining under controls after 1984 was seen as providing an effective "subsidy" to pipelines willing to pay higher than long-run market clearing prices for deregulated supplies. Congress sought to eliminate this possible incentive for interstate pipelines to bid excessively high prices by initially increasing the price of gas delivered to large, price sensitive industrial customers to a level equal to the cost of their alternative fuel. Under this regime, Congress anticipated that pipelines, whose revenues depend upon volumetric throughput, would seek to minimize further increases in the cost of gas that might occur upon deregulation, for fear that industrial demand for natural gas (and therefore throughput revenues) would decline.

A second purpose of the incremental pricing provisions of the NGPA is to shield high priority gas users, such as residential users, from some of the scheduled wellhead price increases allowed by Title I of the Act. This shielding effect is accomplished by channeling to industrial customers a greater than pro rata share of rising prices paid by pipelines. The increased recovery of costs from industrial users results in an offsetting reduction in gas costs recovered from high priority users.

B. *Mechanics of Title II Incremental Pricing.* The incremental pricing program consists of two sets of accounting rules. One set of rules relates to accumulation, at the pipeline level, of "incremental gas acquisition costs." The other set of rules allocates these incremental costs among industrial end users according to their "maximum surcharge absorption capability."

For each unit of gas purchased by an interstate pipeline, the incremental gas acquisition cost is defined as the price paid by the pipeline minus a statutorily prescribed "threshold price" applicable to that gas. If a pipeline buys one MMBtu (million Btu's, or roughly one thousand cubic feet at standard temperature and pressure) of NGPA section 102 (new) gas at the present May 1980 ceiling price of $2.45/MMBtu, it then subtracts the May 1980 incremental pricing threshold of $1.78/MMBtu, which leaves $.67/MMBtu to be placed into the incremental gas acquisition cost account. The $1.78/MMBtu of cost at or below the incremental pricing threshold is placed into the pipeline's purchased gas account and is borne equally by all users. But the $.67/MMBtu in the incremental gas acquisition account is specifically channelled to users subject to the incremental pricing program. The more high-priced gas a pipeline buys, the larger will be its incremental gas acquisition account.

At the same time that pipelines are computing monthly incremental gas acquisition costs, end users are computing their monthly maximum surcharge absorption capability (MSAC). A user's MSAC is defined as the estimated monthly consumption subject to incremental pricing multiplied by the difference between the applicable alternative fuel ceiling and its "base rate". The base rate is determined by the state or local agency having ratemaking responsibility for sales to industrial end users, and does not include the incremental pricing surcharge.

The overall incremental pricing program for a specific interstate pipeline then operates by comparing total incremental gas acquisition costs against aggregate MSACs. If aggregate MSAC's exceed the pipeline's total incremental gas acquisition cost, then the entire amount of those costs is recovered solely from incrementally priced customers. During the initial stage of incremental pricing, all pipeline gas acquisition costs at prices above the incremental pricing threshold are "loaded" onto industrial customers. It is as if industrial customer end-use rates reflect one wellhead price while rates to residential and other high priority customers reflect a lower wellhead price.

But it is unlikely that aggregate MSACs will permanently exceed incremental gas acquisition costs on any pipeline system. This is because the size of the incremental gas acquisition cost account tends to grow exponentially as both the amount of incrementally priced gas and the incremental costs associated with that gas will increase over time.

Eventually, the size of the incremental gas acquisition cost account will equal aggregate MSACs. At this point all incrementally priced users will be, by definition, at their alternative fuel price ceiling. Further increases in the incremental gas acquisition cost account would, if channeled to incrementally priced users, take them above their alternative fuel cost.

To avoid forcing these industrial customers above their alternative fuel cost and potentially driving them from the pipeline's natural gas system, both Title II and the Commission's regulations provide for "spillover" of incremental gas acquisition costs to all customers once incrementally priced users have all reached their alternative fuel ceilings. During this spillover stage, that portion of a pipeline's total incremental gas acquisition costs that exceeds its aggregate MSAC is placed into the system's purchased gas account and is recovered evenly from all customers.

These increases in pipeline purchased gas accounts due to spillover will normally be passed on to all users regardless of whether they are subject to incremental pricing. But when these general cost increases reach incrementally priced users, they increase those users' base rates and thereby reduce their incremental pricing surcharges by reducing the difference between their alternative fuel price ceiling and their base rate.

Accordingly, once spillover begins, further increases in a pipeline's purchased gas costs are effectively borne completely by its exempt (non-incrementally priced) users. This subsequent loading onto exempt users occurs because the incremental pricing program does not force industrial users above their alternative fuel ceilings. What happens during the spillover period is that each industrial user's MSAC and, therefore, its incremental pricing surcharge tend to erode due to increasing base rates. As far as incrementally priced users are concerned, further increases in pipeline gas acquisition costs reduce incremental pricing surcharges and MSAC's but do not increase the overall delivered price.

When viewed from the perspective of residential and other exempt users, spillover signals the start of a temporary period during which they must bear 100 percent of further increases in pipeline gas acquisition costs, even though they may represent only 75 or 80 percent of the pipeline's customers. After spillover begins, the system effectively "loads" purchased gas cost increases onto exempt users until aggregate MSACs of incrementally priced users reach zero. This is referred to as the "catch up" stage.

Finally, the third stage of Title II incremental pricing begins when aggregate MSACs diminish to zero. At that point the incremental pricing system ceases to have any direct effect on user prices. The price of gas to industrial users may rise above the alternative fuel ceiling, but only because the base rate has done so. With incremental pricing surcharges equal to zero, incremental pricing has fulfilled the purpose of easing into higher gas costs, and the historical system of rolled-in pricing to all users resumes.

C. *The Phase I Incremental Pricing Program.* Section 201 of Title II creates a mandatory incremental pricing program applicable to industrial boiler fuel users. The Commission's Phase I rules became effective on January 1, 1980.

The most difficult issue encountered by the Commission in developing its Phase I rules was deciding how to set the alternative fuel ceiling. The Commission recognized that too high an alternative fuel ceiling price could lead to inadvertent loss of industrial load. On the other hand, too low a ceiling price would render the program ineffective in shielding residential and other high priority customers from rising gas costs. These considerations led the Commission to adopt a three-tier alternative fuel ceiling approach.

Under the three-tier system, an industrial boiler fuel user's alternative fuel ceiling price may be based on the price of No. 2 distillate fuel oil, No. 6 low sulfur residual fuel oil, or No. 6 high sulfur residual fuel oil. These three grades of fuel oil represent a wide range of prices, with No. 2 fuel oil significantly more expensive than No. 6 low sulfur fuel oil, which, in turn, is more expensive than No. 6 high sulfur fuel oil. Each facility subject to Phase I would be permitted to use as its alternative fuel ceiling the lowest priced fuel oil that it has the physical capability and legal authority to burn.[4] However, in order to give the Commission time to put the program into operation and to avoid excessive impacts on any facility, the Commission proposed, and the Congress acquiesced in, a one-year moratorium on the upper two tiers until November 1, 1980.

A majority of States have taken action in reponse to the Phase I incremental pricing program that may bear on the Phase II program as well. Specifically, States have altered their end use rate schedules to set the price of natural gas to non-exempt (incrementally priced) users at the alternative fuel cost as referenced in the Commission's regulations and published each month by the Energy Information Administration of the Department of Energy.

Any State taking this action would "zero out" the entire maximum surcharge absorption capability of non-exempt users in the State and thereby eliminate all incremental pricing surcharges to these users. The effect of this action on the part of any State is to cause the entirety of increased revenues collected from non-exempt users to remain within that State. This result is different from what would occur under the Commission's rules, which operate at the interstate level. Under federal incremental pricing, incremental surcharges paid by non-exempt users in one State would contribute to a reduction in the amount of purchased gas costs to be recovered from exempt users in all States served by the pipeline. So it is in the self-interest of a State which contains significant non-exempt industrial load to capture the increased revenues derived from those users for the sole benefit of exempt users within the State.

In a Notice of Proposed Rulemaking on Statewide exemptions from incremental pricing issued on December 21, 1979, the Commission responded to a number of inquiries as to the fairness and legality of this State action.

> In sum, the Commission believes that the Congress has already addressed and affirmed the substitution of State-level incremental pricing (through increased rates to non-exempt users) for incremental pricing at the interstate pipeline level. These considerations lead the Commission to a preliminary view that it should not, and legally cannot, prevent States from raising rates of nonexempt industrial users at or above the federally-prescribed and published alternative fuel cost.[5]

The Commission has yet to take final action on this and other issues in the Statewide exemption proceeding.

D. *Relationship of the Phase II Proposal to Phase I.* The fundamental question that the Commission has addressed in its Phase II proceeding is whether the purposes of the incremental pricing program would be better advanced by a broader scope than is embodied in Phase I. The Commission's decision to propose a broad Phase II rule in its November 1979 Notice of Proposed Rulemaking originated from its view that an expansion would be consistent with both the market ordering and price shielding objectives of the program.

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[4] Legal authority, in this case, refers primarily to applicable environmental restrictions.

[5] Docket No. RM79-47, 45 FR 1081 (January 4, 1980).

Phase I of incremental pricing covers approximately .8 to .9 Tcf, or 7 to 8 percent, of annual interstate volumes. One argument originally offered by the Commission for expanding the program is that Phase I by itself might prove incapable of providing sufficient demand restraint to achieve market ordering in 1985.

> Phase I users are among the lowest priority users of natural gas; if heavily curtailed, Phase I users would no longer be in a position to affect their pipelines' bidding decisions. Under such circumstances, demand restraint could be achieved only through measures applicable to users of higher priority than industrial boilers. (mimeo, p. 9)

With respect to the objective of price shielding, the Commission in its November Phase II Notice anticipated correctly that under Phase I the maximum surcharge absorption capability of industrial boiler fuel users would be less than the amount of purchased gas costs subject to incremental pricing as soon as the rule took effect. Because all industrial boiler fuel users subject to Phase I are now at No. 6 high sulfur alternative fuel ceiling prices, high priority users are currently receiving the full amount of price shielding to be derived from Phase I with its single alternative fuel price ceiling. With Phase I users paying surcharges that have averaged about $.25 per MMBtu over the past few months, the benefit to high priority users has been about 2.5 cents per Mcf. For a typical gas-heating household using 130 Mcf per year, the benefit is approximately $3.00 per year. The Commission believed that the Congress intended a greater measure of price shielding, and so proposed a broad expansion.

Against this background of the purposes and operation of the incremental pricing program, the following section describes both the major themes expressed in the comments received on the Commission's proposed Phase II rule as well as the Commission's reaction to those comments.

IV. Public Comments and Commission Findings on the Proposed Phase II Rule

The Commission's Phase II Notice of Proposed Rulemaking has attracted considerable attention. The following discussion attempts to summarize the dominant themes contained in comments filed in this proceeding. The major themes deal with:

A. The timing of the Phase II Rule.
B. The scope of the Phase II Rule.
C. The alternative fuel price ceiling.
D. Market ordering.
E. Residential and other high priority price shielding.

A final section of this preamble, addressing economic impacts, also deals with a number of comments received on that issue.

Because of the number of comments, no attempt has been made to list in the text all those who commented on each theme. Instead, two or three comments representative of the many others will be cited. All comments and the major issues addressed by each are listed in Appendix A.

A. *The Timing of the Phase II Rule.* The Commission received many comments suggesting that it delay promulgation of its Phase II rule. The American Gas Association and Northern Petrochemical Company as well as others asserted as a threshold matter, that the Commission has the discretion to delay its Phase II rule. They noted that the Phase II rule under section 202 is, by its nature, merely an amendment to the Phase I rule under section 201. They also noted that section 201(a) provides for amendments to the section 201 rule "from time to time". They concluded that the section 202 rule is such an amendment and thus may be made from "time to time" and need not be issued by May 9, 1980.*

Many comments also suggested that the Commission should take a cautious approach, or, indeed, not implement Phase II at all. They suggested that Phase II is premature at this juncture and that further experience with Phase I as well as in-depth economic analyses are required for the Commission to make a reasoned decision on Phase II. Commenters such as Natural Gas Pipeline Company of America submitted that the Commission lacks sufficient data to make a decision now. They noted that 1985 estimated alternative fuel prices, market supply and demand, and other crucial factors are highly speculative at this time. Colorado Interstate Gas Company and others agreed and added their belief that there are so many other crucial incremental pricing rules pending, including small user, statewide, and agriculture exemptions, that the effects of Phase II are currently indeterminable.

Commenters' suggested schedules for implementing Phase II varied widely. Many simply suggested an indefinite delay. Mississippi Public Service Commission and Mississippi Valley Gas Company recommended indefinite delay and added that the Commission should rely on state regulation in the interim period. Others, including Congressman Tom Corcoran of Illinois, sought a delay until more information and experience is gained and all exemption rules are finalized. UGI Corporation urged a delay until the Department of Energy sends to Congress its PURPA section 306 report relating to end-use rate design for natural gas. Others were more specific and suggested delays from one up to ten years. Southern Nevada Industrial Customers suggested that the Commission promulgate the Phase II rule now but establish a much later effective date. Colorado Interstate Gas Company suggested that the Commission ask Congress for more time.

Other comments suggested various phased-in approaches. Ford Motor Company submitted that a phased-in approach with annual reviews will provide flexibility and avoid subjecting more companies to incremental pricing until large volumes of incrementally priced gas hit the market. Cast Metals Foundation suggested a gradual phasing-in at 20 percent of the affected industrials per year until all 100 percent are included in the program.

Few comments expressed favor towards an immediate rule expanding coverage. However, Congressman Dingell of Michigan and Boston Gas Company favored such an approach. Congressman Dingell stated five reasons why a Phase II rule is needed now: (1) Industrials who wanted more gas supplies and are getting them now should pay their fair share for those supplies now; (2) industrials must be encouraged to conserve; (3) market disorders during the transition period before 1985 must be avoided; (4) businesses should be given time to plan for decontrol; and (5) the Commission should have the opportunity to fine-tune its program before 1985. Boston Gas made the point that the Commission may lack statutory authority to expand the program later on.

The Commission is sympathetic to suggestions that it defer Phase II. It would be desirable to have more knowledge and experience with incremental pricing before issuing a Phase II rule. But section 202, in the Commission's judgment, requires a rule to expand the program to industrial non-boiler fuel uses, and leaves no room for delay. It states:

> Not later than 18 months after the date of the enactment of this Act, the Commission *shall*, by rule, prescribe an amendment to the rule required under section 201 * * * (Emphasis added.)

Any expansion of incremental pricing to industrial uses other than boiler fuel requires that a rule be issued on or before May 9, 1980. If disapproved by Congress, provision is made for submitting other Phase II rules. However, a failure to act now may legally foreclose the possibility of a later expansion of the program's scope, should it be decided that such would be in order.

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*Ascard Inc., suggests that the constitutionality of section 202 is in doubt. Other forums are more appropriate for resolution of that question; the Commission's task is to carry out Congress' mandate.

The Commission is not persuaded by the comments of the American Gas Association, Northern Petrochemical Company and others that there is discretion in the NGPA to delay and expand the scope by later rulemaking. To interpret section 202 in relation to section 201(a) in the manner suggested would obviate section 202. The Commission concludes that the language of section 201(a) authorizing amendments does not apply to amendments that seek to broaden the scope of the program, which are the sole consideration of section 202.

The section 202 rule is an amendment to the section 201 rule; but it is not the type of amendment contemplated by section 201(a). According to the Statement of Managers (page 96) section 201 "applies to industrial boiler fuel facilities only." Consequently, any amendment referred to in section 201(a) must relate to industrial boiler fuel use. In contrast, section 202 specifically relates to matters *not* covered by section 201. It calls for a single amendment to the section 201 rule and then only to add coverage to the rule. And section 206(d), which does permit certain amendments to the section 202 rule, only provides for exemptions to that which is already included.

Stated simply, the legislative scheme of Title II is that the Phase II rule delineates the maximum scope of the incremental pricing program. The Commission is of the opinion that once the Phase II rule is adopted, the scope of the incremental pricing program may be contracted but may not be expanded. It follows that in order to give Congress a meaningful Phase II option, the Commission must issue a Phase II rule by May 9, 1980, premised on the understanding that no statutory provision is made for a later expansion of that rule by the Commission.

The Commission must, therefore, act now, even in the face of acknowledged uncertainty, in order to carry out the Congressional intent that it be given a meaningful expansion of incremental pricing from boiler fuel to other industrial uses. A broad Phase II rule can always be followed by section 206(d) exemptions.

The Commission is also sympathetic to and has tried to respond to requests that all other statutorily required exemptions be finalized prior to making the Phase II rule effective. Final rules implementing the mandatory small boiler and agricultural use exemptions are being issued simultaneously with this Phase II rule. But with respect to discretionary exemptions under section 206(d), the Commission is not yet in a position to commit to any broad exemption plan. The Commission is concerned that generic exemptions could become so numerous as to reduce the Phase II rule to a hollow shell. The only prudent course is to provide for the broadest possible program at this time. By doing so, in addition to preserving the scope of the program, the Commission will retain the opportunity to revise and adjust the program as knowledge and experience develop further. Furthermore, during the transition period before 1985, industry as a whole will be able to acclimate itself to scheduled deregulation. Thus, with this approach, a functioning incremental pricing program will be in place when deregulation occurs.

Accordingly, this Phase II rule applies to all industrial gas users. Because the Commission recognizes that industry must have an opportunity to gain an understanding of the Phase II rule and plan for its implementation, the effective date of the Phase II amendment shall be delayed to the maximum extent permitted by the Statute, which is 90 days after the Congressional review period has ended.

B. *Scope of the Phase II Rule.* The Commission's Notice of Proposed Rulemaking proposed to bring all industrial users, other than those specifically excluded by statute and except for those users who consume small amounts of gas, within the scope of the incremental pricing rule. A majority of commenters urged the Commission not to expand the scope of incremental pricing beyond the existing Phase I rule. Most asserted that the proposed broad Phase II rule utilizing a three-tier alternative fuel price ceiling would have disastrous effects on the economy and on their particular industries. These commenters forecast increased inflation and unemployment, fuel switching leading to increased dependence on foreign oil, plant closings, and other effects harmful to industry in particular and the national economy in general. On the other hand, some commenters argued that these forecasts of economic doom were exaggerated and that a broad Phase II rule would best implement Congressional purposes.

Many of the commenters urged the Commission to adopt a liberal approach to granting exemptions from any final rule of broad applicability. Pacific Gas and Electric Company, GTE Products Corporation, and Johns-Manville Corporation, among many others, urged the Commission to exempt uses of natural gas for which no reasonably feasible alternative fuel oil capability exists. Some industrial processes require controlled temperatures or clean flame characteristics which, it is suggested, can be achieved only with natural gas. Many feedstock uses require the particular chemical characteristics of natural gas. Many commenters argued that because of an absence of alternative fuel capability, they are "captive" users unable to switch fuels regardless of price and unable to conserve significantly without reducing production. These users argued that application of incremental pricing to their operations would create economic hardship that would more than offset any direct benefit to exempt, high-priority users. Furthermore, some pointed out that most process and feedstock uses of natural gas are in fact defined as high-priority uses under Commission and state curtailment plans.

For similar reasons, several commenters, including Northern Illinois Gas Company, the American Iron Ore Association and Korf Industries, recommended that natural gas used for plant protection be exempt from incremental pricing. Ideal Basic Industries, Inc. urged the Commission to exempt gas use which is necessary for environmental or industrial safety reasons. Avery International suggested that gas used for mandated emission control devices should be exempt. Phelps Dodge Corporation argued that natural gas used as ignition fuel or for flame stabilization should be exempt. Milweukee Solvay Coke Company urged the Commission to exempt gas used in mixtures of coke-oven gas.

Other commenters asserted that the national interest and economic considerations require that certain industries or classes of industries be exempt from incremental pricing. For example, Potters Industries, Inc. urged the Commission to exempt gas used to manufacture products which are particularly sensitive to competition from foreign imports. A joint comment from North Carolina concerns suggested that the Commission exempt all gas used to manufacture necessities such as food, clothing and shelter. Certain Teed Corporation urged an exemption for the insulation industry, the Cast Metals Foundation urged an exemption for the foundry industry, Sikes Corporation urged an exemption for the ceramic tile industry, the National Clay Pipe Institute urged the same for the clay pipe industry, Schenley Distillers, Inc. recommended an exemption for gas used in the production of anhydrous alcohol for gasohol, and Cabot Corporation urged an exemption for gas used to manufacture corrosion resistant alloys, high temperature alloys, and stainless steels. Other commenters made similar requests citing the national importance of their particular gas uses and the inability of their industries to pass on such cost increases as would occur should the Phase II rule be promulgated as proposed.

From the number and quality of the comments received in this proceeding, it is obvious that the asserted equities involved in determining the scope of Phase II are exceedingly complex. If the Commission were to exempt firms or industries without alternative fuel capability or on some other basis such as social need, national defense, or potential economic disadvantage, the exemptions would soon swallow the rule. To grant some of the requested exemptions and deny the rest could produce highly inequitable results. In order to provide Congress with a proposed rule that would significantly expand Phase I coverage, the Phase II rule must be broad in its application. The record indicates that any significant attempt by the Commission to fashion generic exemptions would be complex and inequitable and could eventually result in a hollow Phase II rule that adds relatively little expansion to the program.

The Commission is continuing to develop a meaningful yet equitable approach for the treatment of generic exemptions from the incremental pricing program. It is the Commission's belief that section 206(d) provides the primary statutory vehicle for granting relief in the form of full or partial exemptions. Any exemption granted pursuant to section 206(d) must undergo Congressional review prior to taking effect, and the Commission believes the Congress, by inclusion of the section 206(d) mechanism in the NGPA, expressed a preference for reviewing exemptions from the program. Thus, the Commission intends to restrict its use of its adjustment authority under section 502(c) of the NGPA. Section 502(c) adjustments will be granted only in those cases where the most special of special hardship can be demonstrated or where a unique set of circumstances unequivocably warrants relief from incremental pricing.

The Straddle Plant Group and several individual natural gas liquid separation facilities argued that the natural gas they purchase should not be subject to incremental pricing. They argued that Title II should not apply because they do not "use" or "consume" all the gas that they purchase. Of the total volume of natural gas which enters a separation plant, most leaves in the form of natural gas, some leaves in the form of natural gas liquids, and the rest is consumed in the process. For example, 100 MMBtu's of gas may enter a particular separation plant. After processing, the gas stream that exits the plant will typically contain 80 MMBtu's of gas. Fifteen MMBtu's may be extracted in the form of natural gas liquids. Only the 5 MMBtu's of natural gas which is consumed in the process is incrementally priced under the Phase II rule below. This is not the result of a partial exemption. In the above example, 80 MMBtu's were returned from the plant in the form of natural gas supplies. Fifteen MMBtu's were separated from the gas stream but remained as useful energy supplies in the form of propane, butane and other natural gas liquids. Because the separation plant actually *uses* only 5 MMBtu's of gas, only the 5 MMBtu's would be subject to incremental pricing under Title II.

Most commenters strongly urged the Commission to continue the exemption for small users of both boiler and non-boiler fuel. The permanent exemption for small boiler users required by section 206(a)(2) of the NGPA will be promulgated in Docket No. RM80-24.[7] Also, a rule applicable to new, small boiler users will be adopted in Docket No. RM79-48.[8]

In the Notice of Proposed Rulemaking issued in this docket, the Commission proposed to exempt from incremental pricing those small users that did not consume more than an average of 300 Mcf per day (or the permanent threshold established in accordance with section 206(a)(2) of the NGPA, if lower) for non-boiler fuel use during any month commencing with May, 1980. Although the comments strongly supported this exemption, several commenters suggested modifications. Mississippi Valley Gas Company, Municipalities for Small Industrial Consumers, and Kyle Associates, among others, recommended that the threshold for the small non-boiler use exemption be set at 300 Mcf per day even if the threshold for the small boiler fuel use exemption is lower as a result of the 5 percent rule required by section 206(a)(2). Northern Natural Gas Company suggested that the small industrial's gas use be examined once a year to establish eligibility for the exemption on an annual basis. Under such a procedure, a small user would not lose its exemption if gas use for one month exceeded 300 Mcf per day because of seasonal variations or unanticipated peak requirements. Northern Illinois Gas Company noted that the small non-boiler use exemption as proposed drew a harsh line. An industrial that uses more than 300 Mcf of gas per day has all of its gas subject to incremental pricing surcharges whether it uses 301 or 100,000 Mcf of gas per day. However, an industrial facility that uses 299 Mcf of gas per day is totally exempt. To relieve this harsh effect, Northern Illinois Gas Company and Koppers Company, Inc. urged the Commission to adopt a rule which would exempt the first 300 Mcf per day of non-boiler use for all industrial facilities. The Commission finds considerable merit in this approach and has made it a part of the Phase II rule.

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[7] *See* Notice of Proposed Rulemaking, Docket No. RM80-24 (March 6, 1980).

[8] *See* Notice of Proposed Rulemaking, Docket No. RM 79-48 (September 28, 1979).

Under the rule adopted by this order, a facility whose Phase II non-boiler uses average 300 Mcf per day or less during any month is totally exempt from incremental pricing (with respect to Phase II use) for that month. If a facility's Phase II uses average more than 300 Mcf per day during a month, only those volumes consumed in excess of 300 Mcf per day are incrementally priced. Thus, a facility averaging 380 Mcf per day of nonboiler fuel use during a month would have 80 Mcf per day subject to incremental pricing surcharges.

The Commission believes that exempting the first 300 Mcf per day of monthly average use is a simple and equitable approach to the small non-boiler use exemption. Problems associated with establishing eligibility for the small user exemption as originally proposed are removed. A facility whose requirements fluctuate from month to month around the 300 Mcf per day level will face lower and more stable gas costs than would have been the case under the originally proposed small non-boiler use exemption. With the approach adopted herein, the impact of incremental pricing will, to a greater extent, be within the control of the small marginal user. For most facilities the increased costs should not be so high as to induce non-productive capital expenditures to install alternative fuel capability. Nevetheless, the increased cost of gas over the 300 Mcf per day average should provide an incentive for such a facility to conserve. The Commission believes that all of a user's natural gas consumption need not be incrementally priced to induce appropriate conservation efforts. Sufficient incentive exists if the marginal use is so priced.

In addition, the Phase II rule places a proportionally greater impact on large users. A facility that averages 2,000 Mcf per day of non-boiler use will have 85 percent of this gas incrementally priced; a facility that averages 600 Mcf per day of such use will have only 50 percent of the gas incrementally priced. Accordingly, the incentive to make conservation or conversion investments is greater for the large users who are more likely to find the absorption of such investments economically feasible.

Small user exemptions for boiler fuel use and non-boiler fuel use will be treated separately under an additive approach. Thus, a facility that in 1977 used an average of 250 Mcf per day as boiler fuel (Phase I use) and which uses an average of 400 Mcf per day in non-boiler (Phase II) applications would qualify for both small user exemptions. Only 100 Mcf per day of the Phase II non-boiler fuel use would be subject to incremental pricing surcharges.

The only industrial non-boiler use of natural gas falling within the potential scope of Phase II that is excluded, specifically excluded from this Phase II rule, is pipeline compressor fuel. The cost of natural gas used as compressor fuel is treated as a general pipeline expense, to be recovered evenly from all customers. Because pipelines would be allowed to pass along the full increased cost of compression if such fuel were incrementally priced, there is no likelihood that the market ordering objective of incremental pricing would be advanced by bringing pipeline compressor fuel within the scope of Phase II.

Concurrently, incrementally pricing pipeline compressor fuel will not contribute to residential and high priority price sheltering, because all customers would pay for the increased cost of compression. The purposes of Title II have, throughout the course of this proceeding, served as the Commission's guide. In the case of pipeline compressor fuel, this guide has led the Commission to the conclusion that incremental pricing should not be imposed.

The rules exempting agricultural uses from incremental pricing are being considered in separate dockets.[9] Exempt agricultural use will not be considered in determining the 300 Mcf per day non-boiler use exemption established by this order. Thus, if a facility uses an average of 900 Mcf per day in non-boiler applications, with 200 Mcf of this eligible for an agricultural exemption, the facility would pay surcharges on 400 Mcf per day. The exempt 500 Mcf per day would be comprised of the first 300 Mcf per day plus the 200 Mcf per day agricultural exemption.

C. *The Alternative Fuel Price Ceiling.* In the Phase II Notice of Proposed Rulemaking the Commission proposed that the alternative fuel price ceiling to be applied to non-exempt industrial facilities subject to Phase II should be the same three-tier system of price ceilings that was adopted in Phase I of the incremental pricing program. However, as explained below, the Commission has determined that a three-tier alternative fuel price ceiling should not be adopted for Phase II. Instead, the Commission has adopted a single-tier alternative price ceiling based on the price of No. 6 high sulfur fuel oil.

Section 204(e) of the Natural Gas Policy Act requires that for both Phase I and Phase II, the Commission is to establish an alternative fuel price ceiling for incrementally priced industrial facilities. That ceiling is to be the price of No. 2 fuel oil unless the Commission determines that the ceiling price is to be an amount not lower than the price for No. 6 fuel oil. Generally speaking, the Commission may reduce the alternative fuel price ceiling below the level of the price for No. 2 fuel oil if such action is necessary to prevent industrial load loss that results in rate increases to high-priority customers. The Commission's specific authorization to reduce the alternative fuel price ceiling is set forth in section 204(e)(2):

> (2) Reduction of appropriate alternative fuel cost allowed.—The Commission may, by rule or order, reduce the appropriate alternative fuel cost—
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> (A) for any category of incrementally priced industrial facilities, subject to the rule required under section 201 (including any amendment under section 202 to such rule) located within any region and served by the same interstate pipeline; or
>
> (B) for any specific incrementally priced industrial facility which is subject to such requirements and which is located in any region;
>
> to an amount not lower than the price, per million Btu's, for Number 6 fuel oil determined by the Commission to be paid in such region by industrial users of such fuel, if and to the extent the Commission determines, after an opportunity for written and oral presentation of views, data, and arguments, that such reduction is necessary to prevent increases in the rates and charges to residental, small commercial, and other high-

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[9] *See* Notice of Proposed Rulemakings, Docket Nos. RM80-28 and RM80-29 (45 FR 15563, March 11, 1980).

priority users of natural gas which would result from a reallocation of costs caused by the conversion of such industrial facility or facilities form natural gas to other fuels, which conversion is likely to occur if the level of the appropriate fuel cost were not so reduced.

In Phase I of the incremental pricing program, the Commission adopted a three-tier system of price ceilings as a means of balancing the objectives of maximizing the passthrough of "high price" gas costs to boiler fuel users and, on the other hand, preventing load shifting that would increase rates and charges to high-priority users.[10] Under this system, regional prices for No. 2 fuel oil, low-sulfur No. 6 fuel oil, and high-sulfur No. 6 fuel oil are designated as ceilings on the price of gas for industrial boiler fuel users. The ceiling for a particular user is to be equal to the price of the least expensive fuel oil that the customer has the installed capability and legal authority to burn.

At the same time that the Commission adopted the rule for a three-tier system of price ceilings, it also adopted an exemption to that rule. Pursuant to its authority under section 206(d) of the NGPA, the Commission determined that until November 1, 1980, a single price ceiling set at the high-sulfur No. 6 price level should be used.[11] The Commission reasoned that a delay in implementing the three-tier system was necessary to permit industry an opportunity to adjust to the incremental pricing program. Also, it was determined that the delay would permit the Energy Information Administration, the organization with responsibility for gathering price data and computing price ceilings, to gain experience in meeting the incremental pricing data needs.

As required by section 206(d)(2) the exemptive rule was submitted to Congress for its review and possible one-House disapproval. Neither House disapproved the delay of the three-tier ceiling and the rule became effective December 1, 1979. In an order that is being issued concurrently with this Phase II rule, the Commission is submitting for Congressional review another rule under section 206(d) that would delay implementation of the three-tier ceiling for Phase I for an additional year.

For Phase II the Commission's Notice of Proposed Rulemaking provided that the three-tier ceiling approach adopted in Phase I be applied to an expanded incremental pricing program. In the Notice, the Commission explained that a three-tier system of price ceilings would maximize the recovery of incremental costs from a non-exempt facility but would also minimize the possibility that a facility will switch to an alternative fuel. In the Notice, the Commission also suggested that a price ceiling identical to that adopted in Phase I would impose the least administrative burden upon incrementally priced facilities.

Written comments and hearing statements submitted in response to the proposal to extend the three-tier system of price ceilings largely opposed its adoption. These comments argued that if incremental pricing is to be expanded to non-boiler fuel uses the price ceiling for facilities subject to Phase II should be no higher than the price for high-sulfur No. 6 fuel oil.

Two major themes supporting a single-tier No. 6 ceiling have emerged. First, many commenters, including AGA, INGAA, the National Association of Manufacturers and several state utility commissions, argued that a three-tier ceiling would cause economic dislocations among those users subject to a Phase II rule. Assuming the ceiling system were to include prices as high as No. 2 fuel oil as an alternative price ceiling, commenters argued, industrial load loss would occur on interstate systems as a consequence of the relocation of facilities using interstate gas that is subject to incremental pricing to intrastate markets where gas is not subject to incremental pricing. Also, many of those submitting comments, such as Herman Energy Services and Sun Pac Foods, argued that if the incremental pricing program is expanded, a three-tier ceiling will exacerbate the competitive disadvantage of domestic industry relative to foreign industry. Other commenters forecasted that a three-tier system of price ceilings could cause some industrial facilities to burn imported fuel oil. And, finally, those who foresaw unfavorable economic impacts resulting from a three-tier system alleged that industrial facilities that currently lack the capability to burn No. 6 fuel oil will make unproductive investments by installing unneeded No. 6 fuel oil burning equipment solely for the purpose of qualifying for a lower alternative fuel price.

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[10] Order No. 50, issued September 28, 1979.

[11] Order No. 51, issued September 28, 1979.

The second major theme argued by those opposed to the adoption of a three-tier ceiling is that such a system will produce inequitable results. Those commenters asserting this view noted that oil prices have increased dramatically since enactment of the NGPA and current prices for No. 6 fuel oil are now at the level that Congress expected for No. 2 fuel oil. Because of these circumstances, the comments argued that at a single-tier No. 6 ceiling, residential and other high-priority gas customers will benefit from price shielding at a level comparable to that envisioned by Congress in 1978. Any additional price shielding resulting from adoption of a three-tier approach will, according to these comments, mask the price of gas to high-priority customers and erode incentives to conserve gas. Moreover, these commenters argued that price shielding of high-priority gas consumers is inequitable to homeowners and others that do not have the capability to burn gas. Commenters advocating this point of view asserted that oil consumers who would otherwise qualify as high-priority users if they had the capability to use gas as their energy source, will be excluded from any price shielding following rapid cost increases. And, it is further alleged, all consumers will subsidize high-priority gas users because higher prices must be paid for those goods that are manufactured using incrementally priced gas. To temper these adverse consequences, these commenters urged the Commission to adopt a single-tier ceiling.

Not all those submitting comments, however, supported adoption of a single-tier, high-sulfur No. 6 ceiling. The Consumer Energy Council of America, the New York State Consumer Protection Board and other commenters urged the Commission to adopt and implement immediately the three-tier approach set forth in the Notice of Proposed Rulemaking. Others, such as the California and Wisconsin public utility commissions, urged the Commission to phase-in the three-tier approach over time or apply different ceiling prices to different gas users, such as a No. 2 ceiling for customers subject to a firm rate schedule and a No. 6 ceiling for the interruptible customers. Finally, other commenters, such as Mississippi Valley Gas and the North Carolina Utilities Commission, *et al.*, urged the Commission to adopt a fourth tier to recognize that there are gas users that cannot convert to fuel oil but must rely upon propane as an alternative fuel.

1. *Single-Tier High Sulfur No. 6 Fuel Oil Ceiling for Phase II.*

The Commission believes that many of the comments opposing a three-tier ceiling provide compelling reasons for adopting a single-tier high-sulfur No. 6 ceiling. Although the Congress made the fundamental determination that high-priority users should be shielded from the near-term adverse transitional effects of deregulation, it left it to this Commission to determine the level of the price ceiling. The only limitation is that the basis for the alternative fuel ceiling prescribed by the Commission must, pursuant to section 204(e)(2), be the prevention of load loss that will cause higher rates and charges to be levied upon high priority and other exempt users. The potential for this effect, as expressed by many commenters, has contributed to the Commission's choice of an alternative fuel price ceiling.

As indicated, many commenters representing a cross section of industrial gas users have stated that a three-tier ceiling presents the potential for severe industrial load loss. Assuming interstate pipelines were to experience such load loss, increased rates and charges to high-priority gas users could be accelerated as a result of the reallocation of fixed costs. This would not be a result intended by the Congress.

But, at the same time that the Commission acts to minimize industrial load loss, it must also advance another objective inherent in the NGPA. The Commission believes that Title II reflects a Congressional determination that non-exempt industrial users should be charged prices that more closely reflect the commodity value of gas. By charging industrial gas users a price closer to that of fuel oil—the benchmark for determining the commodity value of gas—the incremental pricing program recognizes that Federal natural gas regulatory policies have resulted in underpricing gas in relation to its commodity value. Current policy, as articulated by the NGPA, is designed to increase production and to discourage any excessive use of this premium energy source. The economic efficiency arguments made by industrial commenters who caution against artificially low prices to exempt users would seem to suggest that, at the very least, the price of gas to industrial users themselves be raised to the level contained in this Phase II rule.

While the NGPA compels some increase in industrial gas prices, the Commission's choice of an alternative fuel price ceiling should be based on a balancing of several policy objectives which include price shielding and the need to minimize industrial load loss. The Commission judges that such a balance is best struck with a single-tier high-sulfur No. 6 fuel oil ceiling. In adopting this single-tier ceiling, the Commission notes the many comments emphasizing that the price of No. 2 oil has risen to such levels that, should the price of natural gas be forced to that level, the economic impact on industry would be so severe that in many instances it could not be absorbed and rates would be increased to exempt users. It is noteworthy that these same commenters anticipate the cost of gas could reach price equivalence with No. 2 fuel oil upon deregulation in 1985. It is the premature establishment of such prices by regulation rather than by the marketplace that appears most objectionable to industry.

The Commission also notes the substantial rise in oil prices since the NGPA was passed in 1978 and the particularly large increase in distillate fuel oil prices Many commenters, including Stauffer Chemical, argued that these price movements will cause the effect of a No. 6 high-sulfur ceiling to be as substantial as the Congress intended when it passed the NGPA.[12]

The adoption of a minimum commodity/value gas price for industry should also minimize, if not eliminate, the type of servere regional or international competitive disruption that was predicted in many industrial comments. For example, there is considerable doubt as to whether incremental pricing even at higher

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[12] The prices of fuel oil have risen significantly since November 1978, when the NGPA was enacted. The following table summarizes changes that have occurred in delivered industrial prices. Figures are expressed in terms of price per million Btu's.

	November, 1978	Current*
No. 6 high sulfur	$1.73	$3.34
No. 6 low sulfur	2.10	3.87
No. 2	3.10	**5.13
Natural gas	1.75	2.60

*Source: Monthly Energy Review, March 1980.
**Wholesale heating oil.

alternative fuel ceilings as were in the Commission's November Phase II proposal would lead to industrial relocation to intrastate markets. Industrial users may well confront higher delivered prices in intrastate markets after deregulation in 1985 because a greater fraction of intrastate gas will be deregulated at that time. So, an industial user would experience at most a four-year gas cost advantage from such a move. A transitory benefit of this nature would be unlikely to induce significant industrial relocation.

In this order the Commission had determined that the scope of Phase II should be applied broadly to include all industrial gas users except those statutorily exempt. A study undertaken by DOE for purposes of commenting upon this rule suggests that a single-tier ceiling No. 6 fuel oil, applied broadly, will provide residential and commercial gas consumers a high degree of price shielding falling just short of maximum protection in 1984. Accordingly, a reasoned response to those comments that foresee industrial load loss is to adopt a high-sulfur No. 6 ceiling that can be expected to provide a significant degree of price shielding.

Furthermore, the Commission believes that for Phase II, the No. 6 ceiling is more equitable than a three-tier system of ceiling prices. A No. 6 ceiling responds to those comments that argued that it is inequitable for high-priority gas consumers to enjoy price shielding not available to those who must purchase oil to operate their homes and businesses. For residential and other exempt users of gas, it was the decision of Congress to provide a price shielding mechanism that is not available to those energy consumers that purchase and use oil.

A No. 6 alternative fuel ceiling also responds to the commenters that argued that it is inequitable for the general public to pay for those consumer goods which will allegedly bear higher prices caused when manufacturers pass on their incremental gas costs. The comments of the American Gas Association typified this argument. AGA argued that prices for many consumer goods would be increased by the incremental pricing program and that the effect of such price increases would be an accelerated rate of inflation. In a later section of this order, the Commission has more fully considered this argument and concluded that most, if not all, of the increased inflation foreseen by the AGA will not occur. In contrast to AGA's projections, commenters such as DOE and the Council on Wage and Price Stability suggest that competitive considerations would likely preclude the flow-through of a significant measure of increased gas costs. Also, AGA's analysis is premised on an econometric model that contemplates application of a three-tier ceiling. However, when considered together with the adoption of an exemption from incremental pricing for the first 300 Mcf of gas for all incrementally priced industrial facilities, the Commission's adoption of a single-tier ceiling should negate significant price increases for consumer goods.

The No. 6 ceiling adopted here also resolves two other concerns. Several commenters argued that many industrial facilities cannot use oil as an alternative fuel but must rely instead on propane as the atlernative energy source. As indicated in the Notice of Proposed Rulemaking, such facilities would be priced at the level of No. 2 fuel oil, even though the price for propane is often closer to the price of residual fuel oil. By the action taken here, the Commission responds to these comments by adopting a single-tier high-sulfur No. 6 ceiling. Also, a high-sulfur No. 6 ceiling responds to the alleged inequity created as a result of pricing a facility at a No. 2 ceiling unless the facility has the capability to burn No. 6 fuel oil. All facilities subject to a Phase II rule will be priced at a high-sulfur No. 6 ceiling and, consequently, industrial facilities will not be constrained to buy and install equipment with the capacity to burn No. 6 fuel oil.

Finally, in applying the high-sulfur No. 6 ceiling, the Commission has determined that other aspects related to this ceiling approach should correspond to the previous Commission order that adopted a three-tier ceiling in Phase I. Thus, the Commission will request EIA to use the same method for computing the ceiling for Phase II as is used for computing the monthly ceilings for Phase I. Also, the Phase II ceiling will be applied to the 48 contiguous states and 31 metropolitan regions. However, until October 31, 1981, the regions will be limited to the 48 contiguous states.

2. *State Authority to Limit First-Year Impacts.*

The Commission has also determined to provide a mechanism to limit the first-year impacts of the Phase II incremental pricing program. The effect of the Commission's determination could serve to lower the effective alternative fuel price ceiling for some facilities.

Under this mechanism, each state will be given the discretion during the first year of the Phase II incremental pricing program to allocate to other incrementally priced gas users within the state that portion of a non-exempt user's surcharge which exceeds an average of 75 cents per Mcf. In determining whether the surcharge to an industrial user exceeded an average of 75 cents, costs related to gas used for exempt purposes would be included in that determination.

In choosing the 75 cent threshold, the Commission is guided by the likely average cost increases to non-exempt users for the first year and, also, the Commission's judgment about when greater-than-expected incremental cost increases should be ameliorated. The Commission's best estimate is that the average first-year cost increase to Phase II users will average approximately 50 cents per Mcf. However, should oil prices rise significantly faster than anticipated, the first-year cost increases would be greater than expected. If the average cost increases were to increase to 75 cents per Mcf, or 50 percent more than currently anticipated, the Commission believes there would exist a sufficient basis upon which to take mitigating actions.

The mechanism provided here allows a state to assess independently the impact of incremental pricing upon individual industrial users within the state and determine whether a surcharge in excess of 75 cents presents too severe a burden upon that user.

During an informal conference held at the Commission on April 15, 1980, representatives from a number of state regulatory commissions expressed doubt that the authority to limit first-year impacts would be exercised. The representatives cited possible constraints in state laws against such adjustments. They also cited practical and policy considerations which might lead a state commission to decline to make use of any such adjustment authority. Nonetheless, the Commission believes that individual and unforeseeable circumstances may warrant mitigating action and that state commissions are the proper governmental bodies to assess the economic and equity issues involved.

The Commission believes it is desirable to make such authority available for those states which can or wish to make use of such authority. Some states indicated by written comments and oral argument that they may be legally precluded from making such adjustments. Since Congressional review of this rule implies quasi-legislative status, states may have sufficient authority to prevail against a challenge to this mitigating action as violative of state non-discriminatory laws.

D. *Market Ordering.*

1. *The threat of price instability upon deregulation.* The ceiling price of new natural gas will be $2.90 per Mcf, or the energy equivalent of $18.00 per barrel oil (in constant 1980 dollars), at year-end 1984. One day later, price controls on that gas will cease to apply.

The exact price to which new natural gas will rise upon deregulation will depend upon market factors that cannot be fully anticipated at this time. On balance, the record developed in this proceeding indicates that the wellhead price of deregulated gas purchased by interstate pipelines in 1985 is likely to rise significantly as a result of two influences. One influence is the overall condition of natural gas markets; if demand exceeds supply there will be upward pressure on prices. The other influence on new gas prices will be the continued regulation of "old" natural gas at prices below its commodity value. This gas provides an opportunity for pipeline and distribution companies to "roll-in" or average this low-cost gas with high-cost gas and still have a marketable product. The result could be considerable market instability.

Most comments that addressed the pricing issue predicted that after deregulation the average delivered price of gas will move, over time, toward a price equivalent to the delivered price of fuel oil. If so, the dramatic run up in fuel oil prices that has occurred since the NGPA was enacted in 1978 could cause the wellhead price of new natural gas to jump significantly when deregulated on January 1, 1985. Some observers base their assessment of where the wellhead price of new gas will go in 1985 by assuming that it will simply track the price of "high cost" gas that is already deregulated. Some of this "high cost" gas is being purchased today at prices equal to or greater than the equivalent price of No. 2 distillate oil.

The current delivered price of No. 2 fuel oil is about $32.00 per barrel, or $5.50 per MMBtu. Assuming 2 percent per year real growth in the price of No. 2 fuel oil between now and 1985, the price would be in the $6.00 per MMBtu range. If high cost gas prices remain tied to No. 2 fuel oil prices and set the market price for all deregulated gas, then the price of new natural gas will double upon deregulation. Pipelines may be able to pay prices equivalent to No. 2 oil for deregulated new gas in 1985 and yet maintain overall marketability due to their ability to blend this relatively high priced block of gas with lower priced "old" gas.

Natural gas markets can currently support prices in the $6.00 per MMBtu range for limited amounts of "high cost" deregulated gas, but there is reason to question whether such prices can be maintained over the long run. One strong conclusion emerging from the Commission's work on Phases I and II of incremental pricing is that there is a substantial block of demand in the industrial and electric utility sectors that has dual firing (natural gas and fuel oil) capability. Most industrial and electric utility boiler fuel use, and a considerable portion of industrial process use, will switch from gas to oil if relative prices favor such switching. Twenty to twenty-five percent of interstate demand is encompassed by users with dual firing capability. Most of these users have the current or technical capability to burn residual fuel oil, and would presumably switch away from gas well before delivered gas prices approach equivalence with No. 2 fuel oil prices.

Confronted with the prospect of losing so significant a portion of their market, interstate pipelines will attempt to keep the average delivered cost of gas competitive with residual fuel oil prices. As volumes of old gas decline, and therefore the amount of subsidization of new gas by old gas diminishes, the wellhead price of deregulated gas will eventually be below the level of equivalent distillate oil prices. If gas supplies are ample and if fuel oil prices remain as depressed as they are at present, it is possible that any "spike" or surge in deregulated wellhead gas prices in excess of long-run equilibrium levels will be both small and short-lived. Currently, industrial delivered gas prices are in the general range of delivered residual oil prices in most regions of the country.

Important gauges of gas market conditions as 1985 approaches are (1) whether the price of deregulated "high cost" gas is falling in relation to delivered fuel oil prices, and (2) whether other categories of gas, particularly new gas, are selling below the applicable maximum lawful ceilings set by Title I. If high cost gas prices remain at or above No. 2 fuel oil price levels in 1984, and if Title I ceiling prices are acting as binding constraints on wellhead prices, then these indicators would suggest that some significant price jump can be expected to occur January 1, 1985.

The pace at which prices might rise in 1985 is also important. The issue turns in large measure on whether producers of gas to be deregulated in 1985 will have contractual authority to immediately collect market prices, or whether instead the pricing terms of contracts covering deregulated gas will hold the price of that gas to some lower level.

In response to questions posed by the Commission on this issue, various interstate pipelines, including the United Gas Pipe Line Company, indicated that all of the contracts now written for gas that will be subject to deregulation in 1985 contain so-called "most favored nation" clauses that are designed to go into effect on January 1, 1985, or whenever gas covered by the contract is deregulated. These clauses permit a producer (seller) to instantaneously adjust the price of its deregulated gas up to the highest prices being received by any producer in the same field or area in which the production subject to the contract is located. Should this type of clause be the rule rather thn the exception with respect to gas subject to deregulation, then the upward surge of wellhead prices in 1985 could be very swift.

The Commission was unable to determine with certainty that the use of most favored producer clauses is the sole or predominant practice with respect to gas subject to deregulation. This question was directed to the Interstate Natural Gas Association of America (INGAA), which subsequently asked this question of its member pipelines. However, INGAA was unable to provide a generalized statement on pipeline contracting practices.[13]

2. *Volumes subject to deregulation in 1985.* The amount of gas that will be subject to deregulation in 1985, and therefore, the resulting overall impact of deregulation on delivered gas prices, is uncertain. Some comments, nevertheless, attempted to estimate the volume of gas subject to deregulation in 1985. The Department of Energy estimated that between 55 and 65 percent of flowing gas in 1985 will be deregulated. The American Gas Association estimated a somewhat smaller fraction—40 percent of flowing gas in 1985—being subject to deregulation. The Commission believes that these estimates are reasonable and provide a useful range for purposes of examining the effects on consumers of deregulation in 1985.

If 40 percent of the flowing gas stream in 1985 is deregulated and moves up in price by roughly $3.00 from $2.90 per MMBtu to $6.00, then the average price impact on all flowing gas would be approximately $1.20 per Mcf in 1980 dollars. If more than 60 percent of all flowing gas in 1985 is deregulated and moves up by the same $3.00 increment, the average impact on all flowing gas would be closer to $2.00 per Mcf in 1980 dollars. Such changes would represent a 30 percent increase over anticipated residential rates that should be approximately $5.00 per Mcf (constant 1980 dollars) and a 40 percent real increase over industrial rates that will be in the $4.00 per Mcf range at year end 1984.[14]

The Department of Energy expressed strong concern that the impact of a price "spike" at the time of deregulation in 1985 might be even more pronounced on intrastate consumers than upon interstate customers. This larger impact may result because, although gas in the intrastate markets will be regulated at roughly the same level as prices in the interstate market through 1984, the amount of intrastate gas subject to deregulation in 1985 will be far greater. As much as 85 to 90 percent of all flowing gas in the intrastate market may be deregulated under the terms of Title I in 1985. The impact of deregulation on average delivered prices of natural gas in the intrastate market could therefore amount to $2.50 or more per Mcf.

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[13] I regret that we are not in a position to provide you with sufficient information which would warrant the formulation of a generalized statement as to the contracting practices of the interstate gas transmission industry as a whole with respect to this subject. We did undertake to obtain such information. However, the responses received do not provide a representative base, nor do they contain sufficient content to permit a meaningful comparison. In that regard, we found that certain members were very general in their response, and others declined to respond. (Letter from Lawrence V. Robertson, Jr., Vice President, General Counsel and Secretary of INGAA, to Commissioner George Hall, dated February 8, 1980).

[14] Based on 1984 retail rate estimates contained in comments submitted by DOE (Table III-5).

The DOE comment, in noting the larger economic impact of the price "spike" upon intrastate pipeliners and their consumers, went on to explain that intrastate pipelines will be placed at a competitive disadvantage *vis-a-vis* interstate pipelines with respect to bidding for supplies of deregulated gas. The competitive disadvantage to intrastate bidders arises from their smaller endowment of lower-priced gas subject to continuing regulation. The larger endowment of lower priced gas enjoyed by interstate pipelines will permit them to more heavily subsidize purchases of new gas out of their old gas "discounts".

Whether there will be a price spike upon deregulation, and whether the spike will have a significant impact on the distribution of gas between the inter- and intrastate markets will depend to a considerable degree on whether demand and supply for natural gas are in balance in 1985. If demand for natural gas considerably exceeds supply, there is a greater incentive for interstate pipelines to bid the price of deregulated gas to levels above long run market clearing levels. The ability of interstate pipelines to bid higher than long run marginal prices for deregulated gas and yet maintain overall marketability of the gas stream by averaging its cost could result in higher prices being bid by interstate pipelines than intrastate consumers would be willing or able to pay. Should deregulated prices rise in the short run above intrastate market clearing levels, there is the potential for sudden redistribution of gas supplies between inter- and intrastate markets upon deregulation in 1985.

The Commission made a substantial attempt to assess the outlook for natural gas supply and demand in 1985 as a part of its deliberations in this proceeding. On the basis of comments received, the Commission must first emphasize the extreme uncertainty inherent in this inquiry. Natural gas markets have changed dramatically in recent years, and may well experience further change. Nonetheless, the body of comments suggests that the potential for market imbalance in 1985 is very real. Numerous gas supply experts pointed out that the current rate of natural gas production significantly exceeds current rates of reserve additions. Studies submitted for the record in this proceeding, including those by Edward Erickson and James T. Jensen, point to declining availability of conventional gas supplies over the mid- and long-term. The consensus appears to be that conventional lower 48 production may decline from a 1978 level of 19 Tcf to 16–17 Tcf in 1985, and will continue to decline to 12–14 Tcf in 1990.

A decline in production is forecast despite the current and likely continuing upsurge in drilling activity in the United States. According to Erickson's analysis, the rate of drilling activity will have to increase by 15 percent per year in each year between now and 1985 to sustain current production rates of natural gas. The Commission observes that there were record levels of drilling and gas well completions this past year in response to the incentive prices for natural gas allowed under the NGPA. Approximately 12 percent more rotary rigs were active in 1979 than in 1978. A sustained 15 percent per year increase through 1985 may be achievable, but not without a production commitment of unprecedented magnitude and duration.

Further, the scheduled decontrol of crude oil by year-end 1981 has created a roughly $5.00 to $6.00 per MMBtu incentive for new crude oil exploration and production. The wellhead natural gas price schedules under the NGPA provide incentives roughly half of that level. The Commission therefore perceives a potential producer bias toward crude oil and away from natural gas during the next few years despite the positive incentives created by the Natural Gas Policy Act. These factors may make it increasingly difficult to maintain natural gas production levels over the next four to five years.

While the record in this proceeding suggests a decline in natural gas production over the next decade, the comments of many end users, as well as by the American Gas Association, whose members include a number of distribution companies, reflect a growing demand for natural gas. According to the American Gas Association, the "economic demand" for natural gas in 1985 will be 26 Tcf. Current consumption is about 19 Tcf. In light of the current and expected price differential between natural gas and oil products, demand for natural gas may well be increasing.

In summary, most commenters appear to be in agreement that natural gas markets may experience a substantial and potentially abrupt increase in delivered natural gas prices in 1985. The ability of our economic and political systems to withstand a sudden energy price "shock" of the dimension that might occur in 1985 will no doubt be a subject of further debate. James T. Jensen, in his comments, expressed the view that the transition is inevitable and that policies such as incremental pricing which are designed to moderate transitional difficulties may create more problems than they cure. The Commission views this as an issue that, in the instant proceeding, must be resolved by the Congress. But the record does tend to underscore and support the concern that the Congress had in 1978 over the possibility of a disorderly transition to deregulation in 1985.

3. *The Inability of Title II to Achieve Market Ordering.* Despite the need to achieve an orderly transition from regulated to deregulated gas markets, the incremental pricing program as specified by Title II of the NGPA does not appear to generate the type of demand restraint that Congress sought. This conclusion stems from two sets of considerations. The first set derives from the institutions and structure of the natural gas industry. The second set of considerations stems primarily from limitations within the statute itself.

a. *Institutional Considerations.* With respect to institutional factors limiting the ability of incremental pricing to restrain pipeline bidding for deregulated gas, the Commission accepts the view expressed in many comments stating that industrial end users who have little or no capability to switch to alternative fuels (*e.g.*, most feedstock and many process users) are in a relatively weak position to affect the prices that pipelines will pay for natural gas. Only by reducing substantially their takes, through curtailment of operations or plant closings, can they hope to have any significant influence on pipeline bidding operations. Some conservation may be achievable by users without fuel switching capability, but the record before the Commission suggests that the results of such conservation efforts are likely to be too gradual, indirect, and difficult to measure for these effects to have significant short term influence on pipeline gas purchasing decisions. In short, incremental pricing is designed to exploit the demand responsiveness of price-sensitive marginal industrial consumers of natural gas. Where an industrial customer does not have alternative fuel capability, his short-term price responsiveness will be inadequate to produce significant demand restraint.

A majority of comments filed in this proceeding suggest that many process uses of natural gas proposed to be made subject to the scope of the Phase II rule are not capable of using alternative fuels in the short run. The Commission is uncertain as to what portion of the volumes of use subject to the Phase II amendment do in fact have a present or near term capability to use an alternate fuel. The Commission believes that many process users of natural gas currently without alternative fuel capability will add such capability, particularly in the form of electricity, if such natural gas uses are made subject to incremental pricing. For example, comments by the Process Gas Consumers indicate that many natural gas process applications can and will be economically converted to electricity when the delivered cost of gas is more than one third the delivered cost of electricity, because end use efficiencies are greater in electric applications and the continued availability of electricity is more assured. As stated, however, the extent of present or projected alternative fuel capability for uses within the scope of the Phase II amendment is not discernible at this time.

A second institutional consideration perceived as limiting the ability of incremental pricing to accomplish pipeline bidding restraint lies in the attitudes of pipelines toward their customer markets. Several comments explained that pipelines take a relatively long term outlook when it comes to supply acquisition decisions. Pipelines are seldon deterred from acquiring high priced sources solely on the threat that such gas prices might presently make the gas unmarketable to industrial customers on a stand alone basis. Pipelines perceive that declining old gas volumes compel acquisition of additional supplies in order to maintain service to high priority markets and are unwilling to view the short-run threat of unmarketability to the most price sensitive customer as a deterrent to that acquisition. Stated alternatively, pipelines view industrial customers as marginal customers in the short run but view residential and high priority customers, whose demand for gas is far less price sensitive, as the marginal customers over the long run. It is unclear whether end use pricing policy that targets price increases onto the short run marginal customer can be expected to significantly affect pipeline purchasing practices that are dominated by long run supply maintenance considerations.

Still another institutional consideration reflected in the Commission's record in this proceeding is that many industrial users find it hard to believe that they can have any significant influence on the gas purchasing decisions of their interstate pipeline supplier. Many industrial users told the Commission they never talk directly to their interstate pipeline supplier. Instead, they direct any gas supply or price problems to their local distribution company supplier. These commenters do not expect to communicate directly with their interstate pipeline even in the face of rising prices upon deregulation. The comments of interstate pipelines, however, lead the Commission to believe that interstate pipelines are much more sensitive to and concerned about the status of their industrial customers, even industrial customers served indirectly through local distribution company suppliers, than is commonly recognized by the industrial customer.

A final institutional consideration raised in the comments received that may limit the ability of incremental pricing to achieve its market ordering objective is the role of the states in the overall program. As noted previously, a majority of states have raised the rates charged by local distribution companies to industrial customers up to or above the Federally determined alternative fuel price ceiling. This action is taken in order to capture the maximum price shielding benefit for high-priority customers within each state. However, a side effect of state level incremental pricing is that industrial users may perceive the state, rather than the interstate pipeline purchaser, as the cause (and cure) of high delivered gas prices. In effect, state level incremental pricing may remove any perceived reason for industrial customers to appeal to their pipeline to keep the price of gas within reasonable limits. Instead, industrial users may incorrectly perceive that their efforts would be more usefully directed at state ratemaking policy.

b. *Statutory Considerations.* Even if the first set of considerations relating to the possible institutional limitations on the efficacy of Phase II can be overcome, there is a second set of considerations that leads the Commission to question the ability of Title II to achieve its market ordering purposes. These considerations stem from limitations and inconsistencies in the structure of Title II itself. It appears that Congress intended that the threat of industrial load loss create an incentive on pipelines to moderate their purchased gas costs. This threat is present, however, only if incremental pricing can take the delivered price of industrial gas sufficiently near or even above the price of fuel oil to induce fuel switching. But Title II and its legislative history also evidence a Congressional intent that incremental pricing not be responsible for any significant amount of industrial load loss.

Specifically, section 204 of the NGPA instructs that each user's incremental pricing surcharge is to be calculated in such a way as to bring each user's delivered natural gas price up to, *but no higher than,* the alternative fuel ceiling as determined by the Commission. Hence if the Commission sets an intentionally low price in order to avoid unintended fuel switching, the industrial user is also effectively held below its true alternative fuel cost.

Because the alternative fuel ceilings in section 204 operate as *ceilings* rather than *floors* on the price of delivered industrial natural gas, industrial users who reach their ceilings become indifferent to subsequent increases in wellhead prices of gas because the full increase is borne by exempt rather than incrementally priced users. By making the marginal industrial customer indifferent to further increases in the price of deregulated gas, the net consequence of the price ceilings imposed by the incremental pricing program in Title II may be to increase the likelihood of a price spike and disorderly natural gas markets after deregulation rather than facilitate an orderly transition. Pipelines would be left to make their bidding decisions solely on the basis of the ability of less-price sensitive high priority customers to bear the higher costs of deregulated gas.

Whether the foregoing "cap problem" imposed by Title II will cause deregulated markets to be more unstable than without incremental pricing depends primarily upon when industrial customers subject to incremental pricing reach their alternative fuel ceilings and whether the catch up stage [15] has been completed by 1985.

During the catch up period, as industrial user MSAC's are declining to zero, increases in the average wellhead price of gas are borne totally by exempt users. When the catch up period is over, incrementally priced user surcharges vanish and the system reverts to rolled-in pricing. This means that if the system has completed the catch up period before 1985, then industrial users will not be actively capped by their alternative fuel ceilings and will therefore bear at least the rolled-in portion of deregulated gas prices.

Only during the catch up stage can the alternative Title II fuel price ceiling mechanism actually exacerbate market instability by temporarily insulating industrial users from wellhead prices. Rising wellhead prices during the catch up period are spilled over, and have the effect of raising base rates to incrementally priced users. But under section 204, these higher base rates are merely offset by reduced surcharges, so that the delivered price, inclusive of surcharge, is unaffected by changes in pipeline gas costs until the catch up period has been completed. Once the catch up stage is over, industrial rates are no longer held at the alternative fuel price ceiling.

The problem associated with the ceiling price aspects of the incremental pricing provisions of Title II appears to be particularly serious under state level incremental pricing. States may set their rates to incrementally priced industrial users at the Federally prescribed alternative fuel price ceiling. The problem that arises is that states will not have sufficient information to know when the "catch up" stage is over and rolled in pricing should be resumed. The net consequence is that states may keep industrial rates *below* the level that would prevail under rolled-in pricing.

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[15] See discussion of the three stages of incremental pricing in section III-B of this Order.

Under incremental pricing administered at the interstate pipeline level, distributors will know when the catch-up period has ended and will know when they or their state regulatory agency should begin to set the price of gas to incrementally priced users at levels higher than the Federally determined alternative fuel price. But when states supersede the interstate pipeline incremental pricing program, they eliminate the process of displacing surcharges through increased base rates, so that the "signal" to revert to rolled-in pricing becomes garbled. It should be clear, therefore, that the cap, when imposed by state level incremental pricing, may constrain industrial prices to an even greater degree than under the Federal incremental pricing system or under rolled-in pricing. This protracted cap on industrial rates could have the effect of exacerbating the volatility of pipeline bids for deregulated gas while also magnifying the potentially disruptive impact of deregulation upon exempt users.

On the other hand, states may be able to reduce or eliminate the seriousness of the cap problem in Title II if they set the price of gas to industrial users at higher than Federally prescribed alternative fuel ceiling levels. Section 205 of the Act prevents states from setting industrial rates *lower* than the alternative fuel price ceiling but reserves the right of states to impose higher rates to incrementally priced users.

Another possible approach that the states may adopt in an effort to impose market discipline and stability during deregulation would be to deny local distribution companies full pass through of any natural gas costs that the state determines to be a consequence of interstate pipeline purchases at excessively high prices. During its hearings on the Phase II incremental pricing rules, the Commission was told that states in most instances have the legal authority to deny full pass through by their jurisdictional distribution companies of gas acquisition costs considered to be excessively high. It is far from clear, however, that the states would exercise such authority in even the most extreme circumstances following decontrol in 1985. The Commission further points out that it is in no way able, nor does it seek the authority, to compel states to take such action in 1985.

The Title II alternative fuel ceiling on incremental pricing surcharges is determined by the price of alternative fuel oil. The concern with market disorder, however, is directed to the possibility that the price of deregulated natural gas at the wellhead might rise to a level higher than oil-equivalent prices. By placing a ceiling on incremental pricing surcharges such that the industrial incrementally priced user's price cannot go above its alternative fuel oil price, the statute effectively deflects any excessively high portion of deregulated wellhead prices away from incrementally priced industrial users and onto exempt higher priority users. The motivation for this limitation is apparently the Congressional desire to avoid industrial load loss. The consequence, however, appears to conflict directly with the objective of demand restraint and market ordering insofar as incrementally priced users are shielded from the very disorder they are supposed to help cure.

Some form of end-use pricing system based not on oil prices but based instead on measures indigenous to the natural gas system would seem preferable to the oil-based ceiling in order to achieve the Congressional market ordering objective that, in part, led to enactment of Title II. At present, the Commission does not believe that its discretion to set appropriate alternative fuel ceiling prices is a sufficiently broad grant of authority to permit incrementally priced user surcharges to be based upon the performance of the gas market rather than upon prices of alternative fuel oil. The Commission will, however continue to explore this question as well as the related question of whether other discretionary aspects of Title II can be interpreted in a manner that would support achievement of Congress' market ordering objectives.

4. *Further Study and Recommendations to the Congress.* The Commission believes that the appropriate course of action at this time considering the uncertainty that exists as to the appropriate amount of market ordering that will need to be brought to bear in 1985, is to commit to further study of future market conditions. The Commission acknowledges and accepts the view of those who argue that incremental pricing is a complex program. The Commission in its efforts to bring order to a deregulated natural gas market might well produce greater disorder through improperly designed incremental pricing regulations. Even if the Commission were directed by the Congress to exercise broader discretion in its administration of Title II, it does not appear feasible or advisable to attempt to craft a program in 1980 that tries to produce optimal performance in 1985. For these reasons the Commission will continue to examine anticipated 1985 market conditions, and by year end 1983 will deliver to the Congress a report that delineates the overall condition of the gas market and any recommended administrative measures then perceived to be available to the Commission that could be directed toward achieving the appropriate amount of market ordering.

On such measure already under Commission consideration is a proposal to link incremental pricing alternative fuel price ceilings with industrial user curtailment priority. Under this approach each user, rather than this Commission, would determine its own alternative fuel price ceiling. To avoid what would otherwise be a strong incentive of a facility to understate its alternative fuel ceiling and thereby minimize or even avoid its incremental pricing surcharge, the approach would tie the industrial user's curtailment priority to its self-selected alternative fuel price ceiling. Simply stated, those users who nominate higher alternative fuel price ceilings would enjoy higher curtailment priority. The Commission has been interested in this concept and last summer issued a Notice of Inquiry and held an informal conference to receive comments. The Commission's continued strong interest in the approach stems from a desire to substitute market forces for regulatory programs governing both curtailment policy and incremental pricing administration that are of considerable administrative complexity and burden.

In addition to exploring administrative options that might help to cure the cap problem perceived to exist under Title II, the Commission will in its 1983 review also make appropriate legislation recommendations to the Congress to assure that the incremental pricing program does not conflict with its Congressionally stated purpose of easing the transition of natural gas markets to deregulation in 1985 and thereafter.

One specific area of inquiry relevant to Congress' market ordering goals arises from Section 306 of the Public Utility Regulatory Policies Act of 1978 (PURPA), which calls for a study of gas utility rate design proposals. The study is being conducted by the Department of Energy in consultation with this Commission. The Commission, largely on the basis of its work on the incremental pricing program, has come to believe that appropriate wholesale and end use rate design concepts could serve as instruments in preparing natural gas markets for deregulation. However, the Commission also notes, on the basis of the many years in which public attention has been actively directed to electric rate design initiatives, as well as the inherent complexity of gas-rate design, that there is relatively little prospect of a major change in gas retail rate policy and procedures before 1985. Nonetheless, gas retail rate design is the proper focus of increasing public scrutiny.

Traditionally, the fundamental issue in natural gas rate design has involved allocation of pipeline fixed costs to each of the various customer classes being served. This set of issues was the appropriate focus of inquiry during an era in which transportation and distribution costs amounted to 75 percent or more of the delivered price of gas, and the expansion of an efficient natural gas delivery system was of greatest priority. But in recent years the commodity (purchased gas) component of gas rates has risen to the point where it represents more than half the delivered cost of gas.[16] In the future, the commodity component is expected to dominate delivered costs to an even greater extent.

The gas rate design study conducted as directed by PURPA as well as follow-on studies will, it is hoped, lead to substantial examination of the role that gas rate design can play in encouraging stable, orderly and efficient natural gas markets.

E. *Residential and Other High Priority Price Shielding.* The second principal objective intended by the Congress to be achieved through incremental pricing is the partial shielding of residential and other high priority users from the increasing wellhead prices for natural gas allowed by Title I of the NGPA.

Incremental pricing will achieve a measure of price shielding of exempt users by channelling a portion of increased wellhead gas prices to industrial (non-exempt) users of natural gas. To the extent that incrementally priced users absorb higher gas prices, the amount of total costs remaining to be recovered from exempt users will be reduced. Thus, the costs of gas to residential and other exempt gas users will be somewhat lower than if no incremental pricing program were in effect.

As noted previously, the Commission believes that the objective of price shielding can be best advanced by a Phase II rule covering as broad a class of non-exempt users as possible. The Commission also believes, however, that the measure and speed by which price shielding occurs must be tempered by economic and equity considerations. Specifically, the alternative fuel price ceiling should not be set so high as to drive industrial users off of natural gas, thereby creating disarray in both the natural gas market and the economy as a whole. To do so would be inimical to the price shielding objective, because large losses of industrial load would reduce the total amount of incremental gas acquisition costs absorbed by the class of incrementally priced users.

In summary, the Commission concludes that a Phase II rule of broad scope, combined with a moderate alternative fuel price ceiling, is the central feature of a realistic Phase II rule capable of achieving the type of price shielding anticipated by the Congress. According to the Commission's projections in the following section addressing economic impacts, the Phase II rule proposed here is structured with the objective of avoiding economic disruption in the industrial sector and loss of large volumes of non-exempt uses, while benefiting exempt users approximately $.14 per Mcf. For Phase I and Phase II combined, this potential benefit translates for the average household using natural gas for heating and cooking purposes to about $18 per year, assuming a 60 cents per Mcf surcharge.

The Commission perceives this measure of potential savings to exempt users as the present optimum level of price shielding under an administratively workable and economically reasonable Phase II rule, balancing the need to provide some increase in incremental cost absorption by non-boiler fuel industrial users and the need to avoid industrial disruption.

The Commission would submit that this single tier Phase II rule will provide as much price shielding as the Congress originally expected to achieve by Title II because prices of petroleum products have increased dramatically since the NGPA was enacted. The price of No. 6 residual oil at year-end 1980 is likely to be higher than the price of distillate oil in 1978. Because the amount of price shielding is a direct function of the alternative fuel price, whatever benefits accrue to high priority customers from the Commission's decision to use the single No. 6 fuel oil tier for Phase II should be comparable in magnitude to what the Congress had in mind when the NGPA was passed in 1978. The Commission is mindful that the Congress, by means of the statutory review it provided for itself, reserved for Congressional judgment the decision as to whether thus amount of price shielding warrants implementation of an expanded incremental pricing program.

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[16] In 1960 the average wellhead price of gas was 14 cents per Mcf, while the average delivered price to end users was 60 cents. At year-end 1979, the figures were $1.35 per Mcf at the wellhead versus $2.52 per Mcf delivered.

In concluding that a Phase II expansion of the incremental pricing program can advance the price shielding objective, the Commission is cognizant of and has studied carefully the substantial body of comments filed in this proceeding that argued against the achievability of this objective. The most frequently raised objection to the Commission's attempting to implement the Congressional directive to provide enhanced price shielding is the argument that a Phase II rule would ultimately harm exempt users rather than help them. These comments contended that a Phase II rule, especially a broad rule, will actually *increase* the price of gas to exempt users. It was argued that the Phase II rule will result in sufficient load loss among non-exempt users such that a far greater share of fixed transmission and distribution costs will have to be borne be exempt users. These increased costs would include expenses for additional peak shaving and storage facilities that would be necessary if a supplier's interruptible industrial loads were lost. Higher delivered gas prices would also result from increased costs of financing due to service instability confronting pipelines and distributors.

The Columbia Gas Distribution Company, Natural Gas Pipeline Company of America and the AGA, among others, making comments embodying this theme asserted that *any* load loss is incompatible with the Commission's mandate under Title II of the NGPA.

The Commission does not accept the view that *any* load loss would be incompatible with either the letter or the intent of Title II. Under section 204(e), the Commission is granted the authority, but is not required, to lower the alternative fuel price ceiling below the price of No. 2 fuel oil. The first important point, therefore, is that Congress recognized that too high an alternative fuel price ceiling could have an adverse impact on exempt customers, which led it to provide a mechanism allowing the Commission to reduce the ceiling price. But the Congress clearly did not compel the Commission to reduce alternative fuel price ceiling levels in every instance in order to avoid adverse impacts on high priority users.

The Commission seeks to exercise its discretion to set the alternative fuel price ceiling low enough to avoid increased rates to residential, small commercial and other high priority users. But this does not, in the commission's view, mean that there must be absolutely no industrial load loss. In fact, some degree of load loss may be consistent with the objective of maximizing incremental pricing benefits to high priority users. As the Department of Energy explained in its comments, the Commission's approach to determining an appropriate alternative fuel price ceiling should weigh the amount of absorption capability (MSAC's) of remaining non-exempt users against the reduction in fixed charge recovery from users who switch from gas to alternative fuel. Only if the Commission sets an alternative fuel price ceiling so high that the loss in fixed charge recovery exceeds total remaining MSAC's would high priority customers be disadvantaged by incremental pricing.

Furthermore, as discussed more fully in the previous section dealing with market ordering, the Commission believes that the Congress must have intended at least some load loss to result from Title II. Absent a real threat of industrial load loss attributable to incremental pricing, the program cannot be expected to motivate pipelines to restrain their wellhead bidding decisions. Given the program's market ordering purpose, some industrial load loss would be compatible with Title II if the resulting reduction in deregulated gas acquisition costs more than offsets the increased allocation of fixed costs to high priority customers. Such a result would occur if the reduction in industrial demand for gas so reduces bidding pressures on deregulated gas that the average unit cost of gas (at the wellhead) decreases by more than the amount by which the average unit cost of transmission and distribution is increased. In short, the logic of Title II is that some load loss could, and under appropriate circumstances would, actually benefit high-priority customers. Therefore, the argument that the Commission must assure against any load loss is not persuasive.

Even if some load loss is permissible under incremental pricing, Phase II, if adopted, should not cause any significant load loss because the alternative fuel price ceiling will be set at the No. 6 high sulphur oil price level. The comment of E. I. DuPont de Nemours & Company (DuPont) also pointed out that any increase in the price of gas to exempt users that could conceivably occur as a result of industrial load loss would be modest.

Another major theme expressed by TRW, Incorporated, the Procter and Gamble Company and many other industrial users commenting in this proceeding is that incremental pricing will result in "artificially" low delivered gas prices to residential and other exempt users, thereby eroding their incentive to conserve. These commenters argued that distorting energy price signals cannot be justified, and that no Phase II expansion should be put into effect because it would only magnify those distortions. Industrial users such as the Republic Steel Corporation considered this result particularly unfair, because they contended that they have already achieved greater conservation than residential or other high priority users. If the remaining conservation potential is greater among these latter users, then industrial users believed that the nation's energy goals would be ill served by shielding them from the true cost of the energy. Further, DuPont expressed the fear that without more conservation among exempt users, high priority demand will increase to the extent of bringing earlier curtailment of low priority users.

The Commission accepts the need to provide proper price signals to gas users. However, the Commission notes that as long as gas prices are cost-based and reflect average ("rolled-in") historical costs of old contracts with low prices, the prices yielded by such a regulatory practice will not reflect the commodity value of the gas and, therefore, the price signals will not reflect the "true" value of the gas to society. More particularly, the Congress has explicitly made the fundamental social policy decision to redesign the system by which gas costs, in the past, have been allocated among user classes. The Commission regards the explicit reallocation system embodied in Title II as reflecting a Congressional determination going in the other direction—that rolled-in pricing produces unacceptable price shielding of industrial customers.

Furthermore, the Commission believes that the amount of price shielding afforded to high priority users by this Phase II rule will not be of such a magnitude as to mislead them into thinking that their natural gas costs will not rise significantly and steadily over the coming years. Even if the disputable claim that industrial users have less remaining conservation potential than high priority users is correct, the Commission does not accept the argument that price distortions of the magnitude associated with adoption of this Phase II rule would create any significant disincentive to overall conservation of natural gas.

It is also significant that even though Phase II will raise industrial gas prices and reduce the amount of increases borne by residential and high-priority users, the delivered price of gas to incrementally priced users is projected to remain *less than* the price to residential customers in every state.

The average delivered cost of gas to residential customers served by interstate pipelines is approximately $3.70 per MMBtu. The average industrial rate (exclusive of any incremental pricing surcharge) is about $2.65 per MMBtu. Based on current high sulfur No. 6 oil prices, incremental pricing surcharges are about 25 cents, so the average cost of gas to incrementally priced users is $2.90 per MMBtu. The cost of gas to Phase II users will, therefore, be below the price to residential users. Arguments that incremental pricing in general and Phase II in parcticular will dramatically distort price signals to various customer classes might be valid if No. 2 fuel oil had been used as an alternative fuel ceiling. But in light of the Commission's decision to use the single tier high sulfur No. 6 fuel oil ceiling, these arguments take on diminished significance.

The Commission also calls attention to several comments that correctly characterized incremental pricing under Title II as a purely transitional device. The program initially "loads" gas costs onto industrial users and thereby "shields" other users. But the loading stops when industrial users reach their alternative fuel price ceilings. Subsequent increases in gas costs "spill over" onto high priority and exempt users until they eventually catch up to the price path they would have been on without incremental pricing. While the Commission believes that the amount of price distortion arising from Phase II is not sufficient to conflict with national conservation goals, it also attaches additional significance to the fact that any such distortion will be only temporary. It is interesting to note that while some commenters argued that incremental pricing will cause such dramatic distortions in the energy marketplace that it should not be expanded, other commenters argued that the program is so transitory that its administrative burden is unwarranted.

The Commission concludes that at least on the basis of current conditions, there is no basis for a judgment that Title II in general or Phase II in particular will so seriously distort natural gas price signals as to frustrate progress toward more efficient nationwide use of energy resources. The fact that some, but not all, consumers may be paying prices for gas that reflect its true commodity cost, and thereby receive the proper signals, is at least an improvement over the present situation even if it does not go as far as might be required to effect an overall pricing strategy to promote conservation.

A great many comments called attention to potential inequities seen as resulting from successful price shielding of high priority gas users. These comments suggested that the ultimate cost of subsidizing exempt gas users will be borne by non-gas homeowners who instead use more expensive fuel oil, electricity, propane, or other sources. The Process Gas Consumers argued, for example, that "incremental pricing affords these latter homeowners no subsidy on their energy bills; yet, incremental gas pricing will force them to pay higher prices for virtually all consumer goods in order to widen the gap between their own energy bills and those of gas consuming residences."

The Mobay Chemical Corporation suggested that it is inequitable to exempt high priority users who have significant potential to conserve and not exempt some industrial users (*e.g.*, feedstock gas users) who, by definition, have no capacity to conserve. It troubled the Petrochemical Energy Group and the Goodyear Tire and Rubber Company, among others, for some high priority industrial uses (*e.g.*, feedstock and other non-boiler uses) to subsidize certain low priority exempt uses (*e.g.*, cogeneration facilities and electric generation).

Title II will, by design, produce results that are more favorable to some classes of users. But the Congress apparently weighed these inequities against the advantages of an incentive wellhead pricing system in Title I of the NGPA, and, on balance, concluded that one was necessary to accommodate the other. It thus falls upon the Commission to exercise appropriately its discretion in crafting a Phase II program that will advance the objectives of the NGPA while avoiding unacceptable and non-mandated inequities arising from the program.

The Commission believes that it has properly responded to the equity concerns raised in comments. The choice of a single No. 6 fuel oil tier rather than the originally proposed three-tier alternative fuel price ceiling system and the first 300 Mcf per day exemption of Phase II uses will greatly reduce the amount of income redistribution resulting from Phase II. Phases I and II together are expected to reallocate no more than about $1.3 billion per year between non-exempt and exempt users.

Comments by the American Gas Association and Process Gas Consumers asserting that Phase II will induce significant economic disruption and increased overall inflation are premised on dollar flows at least six or seven times greater than will result from the Commission's single tier approach. As noted in the following section on the economic effects of Phase II, the President's Council on Wage and Price Stability is persuaded that even the Commission's original Phase II proposal "is unlikely to increase inflation significantly."

The Commission's decision to adopt both the single tier approach and an exemption for the first 300 Mcf per day of Phase II uses stems from recognized need to mitigate any economic or equity disruptions that might have resulted from the Phase II rule as originally proposed.

One specific inequity, identified by Goodyear and others, is that under a three tier system, Phase II users without No. 6 fuel oil capability would pay gas prices equivalent to No. 2 distillate oil prices. Because of the large difference between the prices of No. 2 and No. 6 fuel oil, high priority industrial users without No. 6 capability would contribute far more to the price shielding of exempt users than would lower priority boiler and other industrial users who in general have, or can relatively easily install, No. 6 capability. In short, a disproportionate share of the subsidy to exempt high priority users would be coming from high priority industrial users if Phase II were to use the three-tier ceiling price system originally proposed. This inequitable result will now be avoided because the Commission will set the alternative fuel price ceiling applicable to Phase I uses at the lowest of the three tiers applicable to Phase II uses.

The Commission believes that the Phase II system contained in this rule for submission to Congress, represents the best balancing of the price shielding objective and the need to avoid disruptive and inequitable impacts which ultimately would work against the best interests of the high priority consumers whom Title II was intended to serve. However, as pointed out in several comments, incremental pricing under Title II is a "blunt instrument" for achieving the socio-economic goals Congress sought to accomplish via price shielding.

Title II provides some price sheltering to all exempt users, regardless of their economic need for this or any other type of subsidy. Phases I and II combined will cause about 25 percent of interstate gas to be incrementally priced. Fully 75 percent of all interstate consumption will share the benefits of surcharges paid by industrial users. Thus, a $.60 per MMBtu surcharge paid by incrementally priced users translates into only a $.20 per MMBtu benefit to exempt users. More significant relief to those unable to pay rising gas costs would be better achieved through other mechanisms such as a targeted incremental pricing program or direct energy cost assistance. However, such mechanisms are beyond the scope of Title II, and therefore not a proper subject of this Commission's actions. The Commission nonetheles notes these views and calls them to the attention of the Congress.

V. Economic Effects of Phase II.

Of major concern to the Commission and a majority of commenters is the need for the Phase II rule to be crafted in a manner that avoids imposing excessive economic stress on individual firms or on the overall economy. The Commission believes that the Phase II rule described herein is adequately responsive to those concerns.

The following discussion assesses the direct cost impact of the Phase II rule on those industries that are significant users of natural gas subject to the rule. Using state-by-state industrial gas consumption profiles, the potential impact on each State is also evaluated. Following the section on direct cost impacts is a discussion of the macroeconomic impacts of the Phase II rule.

A. *Direct Cost Impact.* Many commenters stated that the proposed three-tier program would result in extremely large increases in energy costs. Industrial users without alternative fuel capability predicted that their gas prices would increase on the order of 200 to 300 percent. The impact of such a price increase was depicted as severe. Many firms affected by Phase II compete with other firms not subject to incremental pricing—either intrastate gas users or foreign companies. Faced with such competition, a company would be constrained in the passthrough of increased costs to the consumer. Unable to fully recover increased costs, industries would be forced to absorb the costs through reduced profits. A number of commenters stated that plant shutdowns might result from the proposed three-tier incremental pricing program.

In the final Phase II rule, the Commission has adopted two major changes from its proposed Phase II rule that will significantly mitigate any economic damage arising from the program.

The first change is the decision to use a single tier alternative fuel ceiling approach. With the originally proposed No. 2 fuel oil ceiling price, non-exempt gas users would be faced with surcharges of as much as $3.00 per MMBtu. The Commission's decision to apply a single ceiling price based upon high sulfur No. 6 oil will lead to a much lower average surcharge. At present, depressed market conditions for residual oil imply little or no surcharge. Residual oil prices are below average industrial gas rates in some regions, and are only about 25 cents above gas rates in most localities. Residual oil prices are not expected to remain depressed indefinitely, however. Towards the end of 1980, residual oil prices are expected to recover to a level of about $0.60 per MMBtu above the average industrial gas rate. So the Commission's single tier decision has cut the surcharge impacts on many Phase II users by a factor of five.

Furthermore, due to the second major change adopted by the Commission, this much lower surcharge of 60 cents will be paid only on volumes purchased in excess of 300 Mcf per day. This approach to the small use exemption will give every facility an exemption for a fraction of its total gas use, which will effectively lower the average price increase to Phase II users. The analysis contained in Appendix B estimates the effect of this exemption. The results of that analysis suggest that while the impact of the small use exemption on any particular non-exempt user will depend on the user's size, and aggregate of about 20 percent of the gas that would otherwise be subject to surcharge will be exempted by the small use exemption approach taken by the Commission. As a rule of thumb, an average user's first-year surcharge will be reduced from 60 cents to slightly less than 50 cents per Mcf. The effects of the agricultural use exemption are also addressed in Appendix B.

When all the various categories of manufacturing are summed, the total estimated interstate gas subject to incremental pricing under Phase II is as follows:

SIC	Industry	Non-Exempt Gas, Mcf
28	Chemicals	118,817,803
29	Petroleum	155,511,318
32	Stone, Clay & Glass	250,966,173
33	Primary Metals	314,283,660
22	Textiles	13,050,650
26	Pulp & Paper	2,221,332
—	Other Manufacturing	308,314,412
	Total	1,163,165,348

Assumming that all gas subject to Phase II were surcharged at $0.60 per Mcf, the nationwide aggregate surcharge would amount to $698 million per year. This figure represents a high value, not likely to be soon attained due to presently depressed residual oil prices. This aggregate cost estimate might be considered reflective of calendar year 1981, assuming that residual oil prices rise by year-end 1980 to levels experienced in recent months. Table 3 summarizes by industry and by State the effect of an assumed $0.60 per Mcf surcharge on Phase II uses. The volume of exempt gas over which the surcharge dollars will be spread to achieve a price reduction will, of course, differ substantially among pipelines and among States. Ignoring such variations, a rough measure of aggregate Phase II impact can be gained by noting that the aggregate surcharge would be spread over approximately 9 Tcf of interstate gas consumption for exempt uses. The result is a price reduction of 7.75 cents per Mcf for these exempt volumes. Thus, a residential customer consuming 130 Mcf per year might save about $10 per year as a result of Phase II. This is in addition to an approximately $8.00 per year savings under the Phase I program if average surcharges equal $0.60 per Mcf.

$0.60/Mcf

Table 3

AGGREGATE PHASE II SURCHARGES (thousands of $)
Includes Agricultural and Small Use Exemptions

	SIC-28 Chemicals	SIC-29 Petroleum	SIC-32 Stone, Clay & Glass	SIC-33 Primary Metals	All Other Manufacturing	SIC-22 & 26 Textiles and Pulp & Paper Non-Exempt	TOTAL
Alabama	1,646	730	3,854	8,709	4,516	819	20,274
Arizona	125	---	900	6,513	583	1	8,122
Arkansas	2,049	1,372	3,886	7,930	1,626	253	17,116
California	2,185	23,902	15,328	4,016	7,353	380	53,164
Colorado	35	397	1,882	2,258	2,012	2	6,586
Connecticut	---	---	---	135	731	---	866
Delaware	61	75	---	86	241	---	463
Florida	1,833	1,337	5,319	14	1,295	681	10,479
Georgia	1,691	176	9,810	93	2,407	2,569	16,746
Idaho	700	---	27	---	---	38	765
Illinois	3,552	2,940	10,550	18,607	16,150	133	51,932
Indiana	698	640	5,220	25,467	7,495	8	39,528
Iowa	2,795	---	2,965	1,309	3,069	8	10,146
Kansas	2,734	18,382	7,639	10	2,769	6	31,540
Kentucky	167	968	1,217	2,808	2,261	366	7,787
Louisiana	35,449	26,593	2,941	4,582	8,319	112	77,996
Maryland	250	---	1,544	2,573	1,155	3	5,525
Massachusetts	10	2	666	---	1,570	71	2,319
Michigan	1,504	1,031	4,069	9,302	38,314	147	54,367
Minnesota	18	260	618	6,909	750	26	8,581
Mississippi	721	624	2,252	16	2,615	123	6,351
Missouri	833	519	3,618	209	5,225	3	10,407
Montana	17	551	970	1,714	256	22	3,530
Nebraska	1,648	---	934	36	417	---	3,035
Nevada	142	---	951	34	41	---	1,168
New Hampshire	---	---	---	---	---	19	19
New Jersey	214	10	5,741	344	1,623	75	8,007
New York	483	---	3,455	3,501	7,195	95	14,729
North Carolina	391	---	1,930	83	430	711	3,545
North Dakota	---	37	7	---	---	---	44

(continued on next page)

Table 3

AGGREGATE PHASE II SURCHARGES (thousands of $)
Includes Agricultural and Small Use Exemptions

$0.60/Mcf
Unit Surcharge

	SIC-28 Chemicals	SIC-29 Petroleum	SIC-32 Stone, Clay &. Glass	SIC-33 Primary Metals	All Other Manufacturing	SIC-22 & 26 Textiles and Pulp & Paper Non-Exempt	TOTAL*
Ohio	2,574	1,790	15,988	29,110	14,174	141	63,777
Oregon	303	181	461	901	2,561	71	4,478
Pennsylvania	53	7,305	13,717	32,621	14,537	101	68,334
Rhode Island	---	---	515	22	---	25	562
South Carolina	105	---	6,492	1,591	2,732	1,423	12,343
South Dakota	---	---	619	---	40	---	659
Tennessee	2,722	106	4,610	1,169	3,010	229	11,846
Utah	316	863	1,004	4,384	347	---	6,914
Vermont	---	---	---	---	160	4	164
Virginia	709	---	860	176	983	308	3,036
Washington	400	1,683	40	1,928	254	69	4,374
West Virginia	1,372	135	6,665	2,388	523	---	11,083
Wisconsin	39	35	1,094	999	7,301	120	9,588
Wyoming	748	664	224	---	---	1	1,637
TOTAL	71,292	93,308	150,582	182,547	167,040	9,163	674,726

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* Total reflects elimination of several large industrial facilities identified as using intrastate gas.

B. *Macroeconomic Effects of Phase II.* A large number of commenters have alleged that incremental pricing in general, and Phase II in particular, will be inflationary. The basis for this allegation is that incrementally priced industrial customers will simply raise the prices of their products to offset their increased energy costs. As cost increases are passed through the economy, it is argued that the aggregate impact is amplified through operation of a multiplier effect. The consumer, it is argued, will pay in the long run for such cost increases associated with incremental pricing.

At the forefront of the inflation debate has been a study performed for the AGA by Wharton Econometric Forecasting Associates. The Wharton econometric model has been run a number of times under different assumptions concerning Phase II. The initial run compared the effects of Phase II to a base case of Phase I only. In this analysis, Phase II was expected to bring 90 percent of all interstate industrial natural gas under incremental pricing. The Wharton analysis also assumed a ceiling price based on No. 2 oil, with no downward adjustments, for all Phase II users. Finally, the model incorporated a modified passthrough mechanism that allocated spillover from the surcharge account to all users, thus pushing non-exempt users above their alternative fuel price ceiling and frequently off the gas system. Given such a set of assumptions, it is not surprising that the AGA/Wharton study finds serious adverse impacts attributable to Phase II. Inflation and unemployment rates were predicted to worsen significantly. But this study cannot be considered a useful assessment of the probable effects of the final rule. The model was rerun with a three-tier price ceiling scenario as part of AGA's final submission in this docket. Even this revised assumption considerably overstates the direct cost impact of Phase II because the Commission's final rule sets a uniform ceiling based on residual oil prices for Phase II users.

Notwithstanding the accuracy of these specific input assumptions, other commenters have voiced concerns with the applicability of large scale macroeconomic models for analysis of the effects of a program such as incremental pricing. The Office of Policy and Evaluation of the Department of Energy filed comments which disputed many of the AGA assertions. The DOE analysis maintains that many industrial firms are constrained by competitive pressures and cannot fully pass along increased costs. Moreover, other inputs to industrial production such as exempt gas volumes and electricity generated from gas will benefit from incremental pricing. The commercial sector, a major component of the nation's economy, benefits directly from incremental pricing. DOE projected that if relatively little load loss occurs the net inflationary effect of incremental pricing will be small and possibly negative. However, the DOE submission also indicates that some inflationary impact could result if substantial load loss occurs.

Perhaps more important for purposes of assessing aggregate inflationary pressures arising from Phase II is the total impact in industrial fuel use patterns and pipeline load factors as a result of Phase II. The DOE comments maintain that loss of an individual gas customer to oil is not inflationary per se, and may have little or no inflationary impact if the gas is used by other customers. As long as some users are being curtailed, no aggregate load loss, and therefore no increase in gas delivery costs, will result from Phase II.

As a further step in their submission, DOE performed a macroeconomic analysis of Phase II similar to that performed by AGA. Stressing their contention that macroeconomic models are ill-suited for analyzing the impact of price changes of a single commodity, DOE ran a different model, Data Resources, Inc. (DRI), with the same set of input assumptions as AGA. The results of the two models are strikingly different. The DRI model projects a rate of inflation only slightly higher than under rolled-in pricing until 1985, at which point there would be a slight reduction in the rate of inflation.[17] By 1990, the model actually predicts somewhat less inflation overall as compared to a rolled-in pricing base case. Another run was made to reflect a scenario without significant load loss; the result was essentially the same.

DOE concludes their comments with a critical look at the AGA/Wharton analysis. The direct costs to industry, assuming ACA's estimate of load loss, would amount to $29 billion in 1990. Costs to other sectors of the economy, such as residential and commercial, decline by $16 billion in the same year when compared to rolled-in pricing. The net effect is a $13 billion price increase, in 1990 dollars. This direct price increase is compared by DOE to the tremendous $431 billion increase in inflation projected by the Wharton macroeconomic model. The DOE analysts express doubt that the implicit multiplier of 33, reflecting the assumption that $1 of direct cost increase to industry results in $33 of increased cost to final consumers, could possibly be correct.

The Council on Wage and Price Stability also filed comments in this docket. The Council's submission contains a detailed record of meetings with AGA and DOE technical staff. The record reveals a rejoinder to the DOE analysis submitted to the Council by Wharton. Yet another document submitted by DOE critically examines this rejoinder and questions the validity of its conclusions. This DOE submission provides further comment on the validity of using large-scale macroeconomic forecasting models to analyze the impacts of Phase II. In short, DOE analysts do not believe that any such model currently available is sufficiently detailed and appropriately structured for the task.

The Council notes the sharp disagreement concerning the inflation issue, but nevertheless indicates a belief that the short-term effects of Phase II should be either negligible or anti-inflationary. The Council is skeptical of the extreme inflationary impacts alleged by AGA/Wharton. Finally, the Council echoes DOE's contention that macroeconomic models are poorly suited to such uses as predicting the impact of price changes in a sub-sector of the economy.

In conclusion, the case for a large inflationary impact must be regarded as speculative, even assuming large surcharges to non-exempt users and significant load loss. The Commission notes that the surcharges in the 60 cent per Mcf range which result from the No. 6 oil price ceiling are far less than the $3.00 surcharges which might have resulted from use of a No. 2 oil based ceiling. The small use exemption will lower the effective average surcharge to about 50 cents per Mcf. Finally, the structure of the small use exemption will work to encourage conservation and ultimately may reduce inflation by pricing marginal use of gas closer to its replacement cost.

(Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, 15 U.S.C. 3301, *et seq.*)

In consideration of the foregoing, if neither House of Congress passes a Resolution of Disapproval of the regulations transmitted to them in this Order within 30 days of Congressional review, as determined in accordance with section 507(b) of the NGPA, Part 282 of Subchapter I, Chapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective 90 days following the expiration of the 30-day review period, provided that §§ 282.215, 282.601, and 282.602 shall be effective July 1, 1980.

By the Commission.

Kenneth F. Plumb,

Secretary.

1. The table of sections for Part 282 is amended to add a new § 282.208 entitled *"Exemptions under section 502(c)"* and a new § 282.215 entitled *"Exemption affidavits."*

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[17] Inflation as measured by the GNP implicit price deflator. Measured by the Consumer Price Index (CPI), inflation is lower throughout the period in the incremental pricing case.

2. Section 282.101 is amended to read as follows:

§ 282.101 Purpose.

The purpose of this part is to set forth incremental pricing rules in accordance with Title II of the Natural Gas Policy Act of 1978. The rules require that certain costs of acquiring natural gas be passed through as surcharges on sales of natural gas used as specified in the rules.

3. Section 282.102 is amended by revising paragraph (a) to read as follows:

§ 282.102 Applicability and effective date.

(a) *Uses.* (1) Natural gas used as boiler fuel in industrial boiler fuel facilities on and after January 1, 1980, shall be subject to incremental pricing under this part.

(2)(i) On and after [90 days following expiration of 30-day Congressional review period], natural gas consumed in uses other than as boiler fuel in industrial facilities shall be subject to incremental pricing under this part.

(ii) Shrinkage volumes removed as natural gas liquids or natural gas liquid products from a natural gas stream shall not be subject to incremental pricing under this part.

4. Section 282.103 is amended by revising paragraph (e) and adding a new paragraph (l) to read as follows:

§ 282.103 Definitions.

For purposes of this part:

* * * * *

(e) "Non-exempt industrial facility" means any industrial facility other than one which has been exempted from the provisions of this part in accordance with Subpart B.

* * * * *

(l) "Meter reading period" means the period of time extending from the 20th day of any month up to and including the 19th day of the following month.

5. Section 282.201 is revised to read as follows:

§ 282.201 General rule.

(a) *Statutory exemptions.* Natural gas used for purposes described in § 282.203(a) shall be exempt from incremental pricing as provided in section 206 of the NGPA. Exemptions for such gas may be obtained in the manner prescribed in § 282.215. Adjustments under authority of section 502(c) of the NGPA as may be necessary to prevent special hardship, inequity, or unfair distribution of burdens may be obtained as provided in § 1.41.

(b) *Discretionary exemptions.* Petitions for an exemption under authority of section 206(d) of the NGPA may be filed in the manner prescribed in § 282.206.

6. The text of § 282.203, which currently consists of an introductory paragraph and paragraphs (a), (a) (1) and (2), (b) through (e), is amended as follows:

a. Paragraphs (a), (a) (1) and (2), and (b) through (e) are redesignated as paragraphs (a)(1), (a)(1) (i) and (ii), and (a)(2) through (a)(5) respectively.

b. The introductory paragraph is redesignated as the introductory text of paragraph (a) and revised to read as set forth below.

c. A new paragraph (b) is added to read as set forth below.

For the convenience of the user, the text of the redesignated paragraphs (a), (a)(1), (a)(1)(i), and (a)(3) through (a)(5) is also set forth below.

§ 282.203 Exempt end-uses.

(a) *Statutory exemptions.* In accordance with the provisions of section 206 of the NGPA, natural gas used for the following purposes shall be exempt from incremental pricing under this part:

(1) All gas used for boiler fuel by an industrial boiler fuel facility which was:

(i) In existence on November 9, 1978; and

(ii) * * *

(2) * * *

(3) All gas used in a school, hospital, or similar institution;

(4) All gas used for the generation of electricity by an electric utility; and

(5) All gas used in a qualifying cogeneration facility.

(b) *Partial exemption for non-boiler fuel use.* That volume of natural gas consumed in uses other than as boiler fuel by an industrial facility which is not exempt from incremental pricing pursuant to paragraphs (a)(2) through (a)(5) of this section and which is equal to or less than an average of 300 Mcf per day during any month shall be exempt from incremental pricing under this part.

§ 282.204 [Deleted]

7. Section 282.204 is deleted in its entirety.

§ 282.206 [Amended]

8. Section 282.206 is amended in paragraph (a) by deleting the words "boiler fuel" from the term "industrial boiler fuel facility."

§ 282.207 [Amended]

9. Section 282.207 is amended in paragraph (a) by deleting the words "boiler fuel" from the term "industrial boiler fuel facility."

10. Part 282 is amended to add a new § 282.208 to read as follows:

§ 282.208 Exemptions under section 502(c).

(a) *General rule.* The Commission may, under authority of section 502(c) of the NGPA, exempt any non-exempt industrial facility (or category thereof), in whole or in part, from any provision of this part.

(b) *Procedures.* The procedures set forth in § 1.41 shall apply to an application for an exemption in the nature of an adjustment as described in paragraph (a) of this section.

11. Part 282 is amended to add a new § 282.215 to read as follows:

§ 282.215 Exemption affidavits.

(a) *General.* This section establishes procedures by which owners or operators of industrial facilities may obtain an exemption for natural gas used for the purposes described in § 282.203.

(b) *Obtaining an exemption.* (1) In order to obtain a partial or total exemption from incremental pricing, an owner or operator of an industrial facility shall file an exemption affidavit, as described in paragraph (b)(3), signed and dated by a responsible official associated with the facility, under oath, with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, and send a copy of the executed affidavit to the natural gas supplier serving the industrial facility.

(2) *Commission to provide exemption affidavits.* The Commission will provide exemption affidavits as described in paragraph (b)(3) of this section to natural gas suppliers and to any other interested person upon request. Requests should be directed to the Division of Public Information, Federal Energy Regulatory Commission, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426.

(3) *Contents of exemption affidavits.* (i) The exemption affidavit will provide the owner or operator of an industrial facility with the opportunity to respond to a series of questions so that the owner or operator may establish, if appropriate, the basis for one or more of the exemptions set forth in § 282.203.

(ii) The exemption affidavit will indicate the record retention obligation which may be incurred by the customer under paragraph (b)(7) of this section.

(4) *Effect of filing an exemption affidavit.* If the owner or operator of an industrial facility files an executed affidavit in accordance with paragraph (b)(1) of this section, that volume of natural gas which is consumed in the facility for exempt uses shall be exempt from incremental pricing under this part, if determined in accordance with § 282.504(c)(2)(ii).

(5) *Availability from natural gas suppliers*—(i) *Initial service.* Not later than July 1, 1980, each natural gas supplier shall mail or otherwise supply an exemption affidavit, as described in paragraph (b)(3) of this section, to the owner or operator of each industrial

facility on such natural gas supplier's system.

(ii) *Response date.* Natural gas suppliers which supply exemption affidavits under paragraph (b)(5)(i) of this section shall request that executed affidavits be filed on or before August 1, 1980, in accordance with paragraph (b)(1) of this section.

(iii) *Ongoing availability.* After July 1, 1980, natural gas suppliers shall make exemption affidavits available at their principal place of business on an ongoing basis during regular business hours.

(6) *Effective date of exemption.* (i) If the owner or operator of an industrial facility files an exemption affidavit with the Commission and sends a copy to the facility's natural gas supplier in accordance with paragraph (b)(1) of this section on or before (one day prior to day 90 days following expiration of 30-day Congressional review period), the facility shall be exempt from incremental pricing in accordance with this part as of (90 days following expiration of 30-day Congressional review period).

(ii) If the owner or operator of an industrial facility files an exemption affidavit with the Commission and sends a copy to the facility's natural gas supplier in accordance with paragraph (b)(1) of this section on or after (same date as in paragraph (b)(6)(i) of this section), the facility shall be exempt from incremental pricing under this part as of the beginning of the first full month following the date the exemption affidavit is filed with the Commission and received by the facility's natural gas supplier.

(7) *Record retention.* If the owner or operator of an industrial facility obtains an exemption by filing an affidavit, in accordance with paragraph (b)(1), the owner or operator shall, for a period of at least three years from the date of filing the exemption affidavit, retain all records, documents or data which formed the bases of the responses on the affidavit.

(c) *Public availability of exemption information.* (1) *Executed exemption affidavits.* Copies of executed exemption affidavits which are filed with the Commission shall be available for public inspection through the Division of Public information, Federal Energy Regulatory Commission, Room 1000, 825 North Capitol Street, NE, Washington, D.C. 20426.

(2) *Lists of non-exempt facilities.* (i) On or before November 1, 1980, each natural gas supplier shall file with the Secretary, Federal Energy Reulatory Commision, 825 North Capitol Street, NE., Washington, D.C. 20426, and with each state or local regulatory authority having appropriate jurisdiction over the supplier, a list of all industrial facilities served directly by the supplier which did not qualify for an exemption for their total use of natural gas as of [one day prior to day 90 days following expiration of 30-day Congressional review period].

(ii) On or before November 1 of each year after 1980, each natural gas supplier shall file with the agencies specified in paragraph (c)(2)(i) of this section a revised list of all non-exempt industrial facilities served directly by the supplier. A revised list shall indicate all additions or revisions to or deletions from the prior year's list.

(iii) Lists of non-exempt industrial facilities filed in accordance with paragraphs (c)(2) (i) or (ii) of this section shall indicate the alternative fuel capability of each facility thereon, as established in accord with the provisions of § 282.403.

(iv) Lists of non-exempt facilities filed in accordance with paragraphs (c)(2) (i) or (ii) of this section shall be available for public inspection through the Division of Public Information, Federal Energy Regulatory Commission, Room 1000, 825 North Capitol Street NE., Washington, D.C. 20426.

(d) *Protests.* (1) Any interested person may protest the exemption of an industrial facility from incremental pricing.

(2) The procedures set forth in § 1.10 shall govern the filing of such a protest, except that any person filing such a

protest shall serve a copy of the protest on the affiant of the exemption affidavit.

(3) The affiant may file an answer to any protest. Such answer must be filed within 30 days of the service date of a protest. The affiant shall serve a copy of the answer on the party filing the protest.

§ 282.401 [Amended]

12. Section 282.401 is amended by deleting the words "boiler fuel" and §§ 282.402 through 282.405 are amended by deleting the words "boiler fuel" wherever they appear in the phrase "industrial boiler fuel facility(ies)."

13. Section 282.501 is amended by deleting the words "boiler fuel" wherever they appear in the phrase "industrial boiler fuel facility(ies)" in paragraphs (c) and (c)(2) and by revising paragraphs (c)(3) and (d) to read as follows:

§ 282.501 General rule.

* * * * *

(c) * * *

(3) the maximum surcharge absorption capability of a non-exempt industrial facility for any calendar month shall be determined by utilizing the alternative fuel price ceiling(s) applicable to that calendar month and the meter reading(s) made during the meter reading period beginning on the 20th day of such month. If more than one meter reading is made in a meter reading period, a cumulative total of all meter readings made in such period shall be determined.

(d) Each month, in the case of interstate pipelines, the amount accumulated in the pipeline's unrecovered incremental gas costs account which cannot be recovered by way of incremental pricing surcharges shall be cleared from that account to account 805.2, Incremental Gas Cost Adjustments, in accordance with § 282.502.

14. Section 282.503 is amended by deleting the words "boiler fuel" from the term "industrial boiler fuel facilities" in paragraphs (a)(2)(ii) and (c) and by revising paragraph (b) to read as follows:

§ 282.503 PGA reduction.

* * * * *

(b) *Projected MSAC of a non-exempt industrial facility.* (1) The projected MSAC of a non-exempt industrial facility for a coming PGA period shall be calculated by a natural gas supplier in accordance with the following formula, in which the symbol " ˆ " indicates a projection:

$$\hat{M} = \frac{[(\hat{AB}_1 - \hat{RB}_1)\hat{VB}_1 + (\hat{AS}_1 - \hat{RS}_1)\hat{VS}_1]}{1 + \hat{T}_1} + \frac{[(\hat{AB}_2 - \hat{RB}_2)\hat{VB}_2 + (\hat{AS}_2 - \hat{RS}_2)\hat{VS}_2]}{1 + \hat{T}_2} + \cdot \cdot \cdot + \frac{[\hat{AB}_n - \hat{RB}_n)\hat{VB}_n + (\hat{AS}_n - \hat{RS}_n)\hat{VS}_n]}{1 + \hat{T}_n}$$

where:

$\hat{M}$=Projected MSAC of the non-exempt industrial facility.

$\hat{A}B$=Projected alternative fuel price ceiling, plus taxes, for the boiler fuel consumed in a non-exempt use by the industrial facility, as determined in accordance with paragraph (b)(2)(i) of this section.

$\hat{R}B$=Projected rate per million Btu's (excluding any incremental pricing surcharge), plus taxes, at which the industrial facility will purchase natural gas for non-exempt boiler fuel use, as determined in accordance with paragraph (b)(3)(i) of this section.

$\hat{V}B$=Projected volume of natural gas (at 1,000 Btu's per cubic foot) that the industrial facility will purchase from the natural gas supplier and use for non-exempt boiler fuel, as estimated for each of the months "1" (one) through "n" of the PGA period.

$\hat{A}S$=Projected alternative fuel price ceiling, plus taxes, for all natural gas consumed in a non-exempt use other than as boiler fuel by an industrial facility, as determined in accordance with paragraph (b)(2)(ii) of this section.

$\hat{R}S$=Projected rate per million Btu's (excluding an incremental pricing surcharge), plus taxes, at which the industrial facility will purchase natural gas for consumption in a non-exempt use other than as boiler fuel, as determined in accordance with paragraph (b)(3)(ii) of this section.

$\hat{V}S$=Projected volume of natural gas (at 1,000 Btu's per cubic foot) that the industrial facility will purchase from the natural gas supplier in excess of otherwise exempt volumes and an average of 300 Mcf per day and consume in a use other than as boiler fuel, as estimated for each of the months "1" (one) through "n" of the PGA period.

$\hat{T}$=Projected total percentage tax rate reflecting any state and local taxes applicable to an incremental pricing surcharge.

n=Last month of the PGA period.

(2) *Projected alternative fuel price ceilings*—(i) *Non-exempt boiler fuel use* As a value for "$\hat{A}B$" for each of the months "1" (one) through "n" of the coming PGA period, a natural gas supplier shall use the most recently established alternative fuel price ceiling applicable to the facility's non-exempt boiler fuel use, plus taxes, unless the supplier elects to estimate the applicable alternative fuel price ceilings for each month. In that case, the estimated ceilings, plus taxes, may be used as values for "$\hat{A}B$".

(ii) *Non-exempt use other than boiler fuel.* As a value for "$\hat{A}S$" for each of the months "1" (one) through "n" of the coming PGA period, a natural gas supplier shall use the most recently established alternative fuel price ceiling applicable to the non-exempt use of gas other than as boiler fuel in the facility, plus taxes, unless the supplier elects to estimate the applicable alternative fuel price ceilings for each month. In that case, the estimated ceilings, plus taxes, may be used as values for "$\hat{A}S$".

(iii) *Assistance for local distribution companies.* If a local distribution company desires assistance in estimating applicable alternative fuel price ceilings for each of the months of the coming PGA period, the interstate pipeline which supplies the local distribution company shall provide such assistance.

(3) *Projected rates*—(i) *Local distribution company.* (A) *Non-exempt boiler fuel use.* As a value for "$\hat{R}B$" for each of the months "1" (one) through "n" of the coming PGA period, a local distribution company shall use its effective boiler fuel industrial gas sales rate per million Btu's at the time of projection, plus taxes, but exclusive of any incremental pricing surcharges, unless the local distribution company elects to adjust such rate to reflect general rate changes which it is known will occur during the PGA period under authority of a state or local regulatory body. If the local distribution company elects to adjust the rate, the values used for "$\hat{R}B$" may reflect the adjustments for the months of the PGA period for which the adjustments are appropriate.

(B) *Non-exempt use other than boiler fuel.* As a value for "R̂S" for each of the months "1" (one through "n" of the coming PGA period, a local distribution company shall use its effective non-boiler fuel industrial gas sales rate per million Btu's at the time of projection, plus taxes, exclusive of any incremental pricing surcharges, unless the local distribution company elects to adjust such rate to reflect general rate changes which it is known will occur during the PGA period under authority of a state or local regulatory body. If the local distribution company elects to adjust the rate, the values used for "R̂S" may reflect the adjustments for the months of the PGA period for which the adjustments are appropriate.

(ii) *Interstate pipeline*—(A) *Non-exempt boiler fuel use.* As a value for "R̂B" for each of the months "1" (one through "n" of the coming PGA period, an interstate pipeline shall use its effective boiler fuel industrial gas sales contract rate per million Btu's at the time of the projection, plus taxes, but exclusive of any incremental pricing surcharges, unless the pipeline elects to adjust such rate to reflect rate changes which it is known will occur during the PGA period.

(B) *Non-exempt use other than boiler fuel.* As a value for "R̂S" for each of the months "1" (one) through "n" of the coming PGA period, an interstate pipeline shall use its effective non-boiler fuel industrial gas sales contract rate per million Btu's at the time of the projection, plus taxes, but exclusive of any incremental pricing surcharges, unless the pipeline elects to adjust such rate to reflect rate changes which it is known will occur during the coming PGA period.

* * * * *

15. Section 282.504 is amended by deleting the words "boiler fuel" from the term "industrial boiler fuel facility(ies)" in paragraphs (a), (c)(1), (c)(3), (c)(4), (d)(2) and (d)(3)(ii), and by adding paragraph (c)(1)(iii) and revising paragraph (c)(2) to read as follows:

§ 282.504 Incremental pricing surcharge.

* * * * *

(c) *Surcharges on non-exempt industrial facilities.* (1) * * *

(i) * * *

(ii) * * *

(iii) For the period November 1, 1980, through October 31, 1981, a state may elect to allocate that portion of an industrial facility's surcharge as determined in accord with subdivisions (i) or (ii) of this subparagraph which is applicable to non-boiler fuel use of natural gas and which exceeds 75 cents per Mcf to other non-exempt industrial facilities within the state.

(2) *MSAC of a non-exempt industrial facility.* (i) The MSAC of a non-exempt industrial facility for any calendar month shall be determined in accordance with the following formula:

$$M = \frac{[(AB-RB)(VB) + (AS-RS)(VS)]}{1 + T}$$

where:

M=MSAC of the non-exempt industrial facility.

AB=Alternative fuel price ceiling, plus taxes, applicable to the boiler fuel consumed in a non-exempt use by the industrial facility during the subject calendar month.

RB=Rate per million Btu's (excluding any incremental pricing surcharge), plus taxes, at which the industrial facility purchased gas for consumption as boiler fuel in a non-exempt use from the natural gas supplier during the month.

VB=Volume of natural gas (at 1,000 Btu's per cubic foot) suplied by the natural gas supplier to the industrial facility for consumption as boiler fuel in a non-exempt use during the month, as determined in accordance with paragraph (c)(2)(ii) of this section.

AS = Alternative fuel price ceiling, plus taxes, applicable to consumption of gas in a non-exempt use other than as boiler fuel by the industrial facility during the subject calendar month.

RS = Rate per million Btu's (excluding any incremental pricing surcharge), plus taxes, at which the industrial facility purchased gas for consumption in a non-exempt use other than as boiler fuel during the month.

VS = Volume of natural gas (at 1,000 Btu's per cubic foot) supplied by the natural gas supplier and consumed in a use other than as boiler fuel by the industrial facility that is not otherwise exempt and that exceeds an average of 300 Mcf/day during the month, as determined in accordance with paragraph (c)(2)(ii).

T = Total percentage tax rate reflecting any state and local taxes applicable to an incremental pricing surcharge.

(ii)(A) For the period January 1, 1980, through October 31, 1981, the volume of natural gas supplied to a non-exempt industrial facility during a month may be determined in accordance with § 282.207.

(B)(*1*) Subject to clause (*2*), on and after November 1, 1981, the non-exempt volume of natural gas supplied by a natural gas supplier to a non-exempt industrial facility during a month shall be deemed to be the total volume of natural gas supplied to the facility during the month, unless the natural gas supplier serving the facility distinguishes the volumes used for non-exempt uses from the volumes consumed in exempt uses on the basis of submeter readings. If volumes consumed in non-exempt uses are so identified, such volumes shall be the basis for determining the MSAC of the industrial facility in accordance with subdivision (i) of this subparagraph.

(*2*) Certified monthly estimates determined in accordance with § 282.207 may be utilized to determine the volume of natural gas consumed in the facility for non-exempt uses for a period following November 1, 1981: *Provided*, That the owner or operator of the facility has obtained a purchase order for all submeters which will be needed in the facility by November 1, 1981, and such submeters will be installed within a reasonable period of time.

* * * * *

16. Section 282.506 is revised to read as follows:

§ 282.506 Refunds.

(a) *Non-exempt boiler fuel use.* The jurisdictional portion of any refund (including interest applicable thereto) which is attributable to that portion of service provided to and consumed as boiler fuel for a non-exempt use by industrial facilities prior to January 1, 1980, which had not been flowed through to such users as of December 31, 1979, shall be flowed through as a lump sum payment in appropriate amounts to each appropriate natural gas supplier for the benefit of such users. Such refunds shall be calculated on the basis of sales to such users during the period when the rates which gives rise to the refund were in effect.

(b) *Non-exempt use other than boiler fuel.* The jurisdictional portion of any refund (including interest applicable thereto) which is attributable to that portion of service provided to and consumed in a non-exempt use other than as boiler fuel by non-exempt industrial facilities prior to (90 days following expiration of 30-day Congressional review period) which has not been flowed through to such users as of (day prior to day 90 days following expiration of 30-day Congressional review period) shall be flowed through as a lump sum payment in appropriate amounts to each appropriate natural gas supplier for the benefit of such users. Such refunds shall be calculated on the basis of sales to such users during the period when the rates which give rise to the refund were in effect.

17. Section 282.601 is amended by revising paragraph (c) to read as follows:

§ 282.601 FERC gas tariff provisions.

* * * * *

(c) *Filing dates.* The incremental pricing surcharge provision and revised PGA provision shall be filed with the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 and served on all parties by July 1, 1980. The provisions shall become effective on August 1, 1980, unless disapproved in whole or in part by the Commission.

18. Section 282.602 is amended by revising paragraph (a) to read as follows:

§ 282.602 Tariff sheets.

(a) *General rule.* (1) On or before August 1, 1980, for the period (90 days following expiration of 30-day Congressional review period), to the effective date of the pipeline's next normally scheduled PGA filing, each interstate pipeline shall file concurrently:

(i) A tariff sheet reflecting a reduced PGA rate as determined in accordance with § 282.503; and

(ii) A tariff sheet reflecting the projected incremental pricing surcharges for each month, as determined on the basis of data used in deriving the reduced PGA rates referenced in subdivision (i) of this subparagraph, for each of the direct sale non-exempt industrial facilities and the aggregate amount applicable to each sale-for-resale customer on the pipeline's system.

* * * * *

19. Section 282.603 is amended by revising paragraph (a) to read as follows:

§ 282.603 Informational filings.

(a) *General rule.* For informational purposes, each month commencing with September 1980, each interstate pipeline company shall file with the Commission a statement setting forth the incremental pricing surcharge actually billed to each non-exempt industrial facility and sale-for-resale customer on its system in the preceding month.

* * * * *

[Appendix A, "Summary of Comments of Phase II Rulemaking," and Appendix B, "Estimate of Volumes Subject to the Phase II Rule," are not included here. They may be found at 45 *Federal Register* 31622 (May 13, 1980).]

[¶ 30,158]

45 F. R. 33601 (May 20, 1980)

18 CFR Part 282

[Docket No. RM80-29; Order No. 83]

Section 206(d) Rule Exempting Agricultural Uses From Incremental Pricing Surcharges

May 7, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule, Subject to Congressional Review.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts a rule which, if not disapproved by either House of Congress, will exempt agricultural uses of natural gas from incremental pricing surcharges until such time as the Commission determines there is an economically practicable and reasonably available alternative fuel for a particular use.

EFFECTIVE DATE: Immediately effective upon expiration of 30-day Congressional review period, if not disapproved by either House of Congress.

FOR FURTHER INFORMATION CONTACT: Alice Fernandez, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C., (202) 357-8095.

I. Background

Title II of the Natural Gas Policy Act of 1978 (NGPA) requires the Commission to prescribe and make effective a program of incremental pricing of natural gas used as boiler fuel in large industrial facilities. Under section 202 of Title II, the Commission may expand the incremental pricing program to industrial uses other than boiler fuel use. Any expansion proposed by the Commission is, pursuant to the statute, subject to Congressional review.

Section 206(b) of the statute sets forth the parameters of an exemption from the incremental pricing program for agricultural uses of natural gas.

Section 206(b) provides as follows:

> (b) Agricultural Uses of Natural Gas.—
>
> (1) Interim Exemption.—During the period preceding the effective date of any permanent exemption under paragraph (2), the rule prescribed under section 201 shall not apply to any facility to the extent of any agricultural use of natural gas.
>
> (2) Exemption by rule.—Not later than 18 months after the date of the enactment of this Act, the Commission shall prescribe and make effective a rule providing for the exemption from the rule required under section 201 (including any amendment under section 202 to such rule) any facility with respect to any agricultural use of natural gas for which the Commission determines that an alternative fuel or feedstock is not—
>
> (A) economically practicable; or
>
> (B) reasonably available.
>
> (3) Agricultural use defined.—For purposes of this subsection, the term "agricultural use", when used with respect to natural gas, means the use of natural gas to the extent such use is—
>
> (A) for agricultural production, natural fiber production, natural fiber processing, food processing, food quality maintenance, irrigation pumping, or crop drying; or
>
> (B) as a process fuel or feedstock in the production of fertilizer, agricultural chemicals, animal feed, or food.

In accord with the statutory directive, the agricultural use exemption is to consist of two distinct phases. Subsection (1) of section 206(b) provides that all "agricultural uses," as defined in section 206(b)(3), shall be exempt from incremental pricing surcharges for the duration of the initial phase (characterized in the statute as the "interim exemption").

In the second phase of the agricultural exemption, the statute provides that the Commission shall prescribe a rule to exempt permanently from incremental pricing surcharges those agricultural uses—again utilizing the definition set forth in section 206(b)(3)—for which "the Commission determines that an alternative fuel or feedstock is not—(A) economically practicable; or (B) reasonably available."

The Commission implemented the interim exemption for agricultural uses through provisions in the regulations adopted for Phase I of the incremental pricing program.[1] Specifically, § 282.203(b) of the Commission's regulations provides that "all gas used for an agricultural use" is exempt from incremental pricing surcharges. The definition of "agricultural is use" set forth in § 282.202(a) of the Commission's regulations. This definition incorporates by reference the listing of essential agricultural uses as determined by the Secretary of Agriculture and certified to the Commission pursuant to section 401(c) of the NGPA. The definition in § 282.202(a) also includes other agricultural uses of natural gas which the Commission has determined come within the bounds of the definition set forth in section 206(b)(3) of the NGPA.

Section 206(b)(2) of the NGPA provides that the Commission shall adopt the rule defining the permanent agricultural exemption "not later than 18 months after the date of the enactment of this Act," *i.e.*, May 9, 1980.

On March 6, 1980 (45 FR 15563, March 11, 1980), the Commission proposed two companion rules for the purpose of meeting the statutory directive to promulgate a permanent agricultural exemption by May 9th. The proposal in Docket No. RM80–28 would have exempted from incremental pricing surcharges any agricultural use listed in § 282.202(a) of the Commission's regulations as to which the Commission had made a determination that an alternative fuel or feedstock was either not economically practicable or reasonably available. The proposal, however, provided no alternative fuel or feedstock test for the Commission to utilize to arrive at such a determination. Thus, the net effect of the proposal, if adopted by itself, would have been to make all agricultural uses subject to incremental pricing surcharges.

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[1] Order Nos. 49, 50, 51, issued September 28, 1979 (44 FR 57725, October 5, 1979).

As a companion proposal to that set forth in Docket No. RM80–28, however, the Commission proposed in this docket, Docket No. RM80–29, to exempt all agricultural uses from application of any alternative fuel test through April 30, 1981. This proposal was based on the authority vested in the Commission by section 206(d) of the NGPA, which grants the Commission the authority to "provide for the exemption, in whole or in part, of any other incrementally priced industrial facility or category thereof. . . ." The proposal to exempt agricultural uses through April 30 of 1981 would, if adopted by the Commission as a final rule, have been subject to Congressional review and a possible vote of disapproval by one House.

The Commission stated in the Docket No. RM80–29 proposal the four primary reasons it had determined to propose an exemption for agricultural uses through April of 1981. The Commission expressed its belief that the scope of the incremental pricing program should be known before work on the details of the agricultural exemption was undertaken. The scope of the program is, of course, dependent on Congressional review of the Commission's final action on the Phase II proposal in Docket No. RM80–10, which is being issued concurrently with this order.

The Commission also indicated it hoped that the alternative fuel test required under section 206(b) for the incremental pricing program could be made consistent with the alternative fuel test which must be prescribed for purposes of the Commission's curtailment program under section 401 of the NGPA. The Commission further indicated an extended exemption for agricultural uses would be consistent with what has been the Commission's cautious approach to implementation of the incremental pricing program. Finally, the Commission indicated it believed neither its Staff nor affected members of the regulated industries had available sufficient resources to dedicate to development of an alternative fuel test in the time period involved to meet the May 9th deadline for promulgation of a final rule.

II. Comments Received

A public hearing on the proposals in Docket Nos. RM80–28 and RM80–29 was held in Washington, D.C. on March 27, 1980. Seven persons presented oral statments at the hearing, representing various agricultural and industrial associations. In addition, sixteen written comments were submitted to the Commission on the companion proposals.

Several of the commenters argued that the Commission should not adopt the proposal in Docket No. RM80–28, since the effect of that action, by itself, would make all agricultural uses subject to incremental pricing surcharges.

Several of the commenters urged the Commission simply to extend the interim exemption—required by section 206(b)(1)—for an additional year rather than attempting to meet the directive of section 206(b)(2).

One industrial end-user group stated its view that agricultural uses should not enjoy an extended exemption from incremental pricing surcharges if all other industrial users—*i.e.*, process and feedstock users—become subject to the program under Phase II.

III. Rule Adopted

The Commission has carefully considered all of the policy arguments and legal considerations raised in the written comments submitted in Docket Nos. RM80–28 and 29 and discussed in the public hearing on the proposals. The Commission's analysis has led it to conclude that the proposals should not be promulgated as final rules.

In contradistinction to the proposed action, the Commission has concluded that the exemption for agricultural uses

should not be extended prospectively for a definite additional twelve months. The Commission has reached this determination because it believes that the clear thrust of Title II of the NGPA, and particularly section 206(b)(2), is that agricultural uses ultimately be subject to being incrementally priced, except in those cases where the Commission makes a determination that another fuel or feedstock is not a viable alternative for a particular agricultural use.

However, the Commission still has the first three concerns articulated above which led it to propose an extended exemption. The Commission believes it will have adequate opportunity to address these concerns under the action it has determined to take and as described below. The fourth concern of the Commission—adequate staff resources within both the Commission and impacted parties—has become less crucial as the various threads of the incremental pricing program have been drawn together.

Rather than adopting an exemption for agricultural uses for the period of the next year, the Commission has determined to adopt an exemption of unstated length pursuant to the authority of section 206(d), which shall continue in effect until such time as the Commission determines that an alternative fuel is both economically practicable and reasonably available for a specific agricultural use.

The exemptive rule does not have a definite duration, and thus will provide the Commission with the opportunity to analyze in detail and receive public comment on an appropriate test to use in order to reach the determination that there is a practicable and available alternative fuel to natural gas in the various agricultural uses.

Under the rule set forth below, all agricultural uses, as designed in section 206(b)(3) of the NGPA and § 282.202(a) of the Commission's regulations, will be exempt from being incrementally priced until further action is taken by the Commission. This exemption will apply to Phase II users as well as Phase I users, should the Phase II expansion of the incremental pricing program become effective.

IV. Alternative Fuel Test To Be Developed at Future Date

As stated in the proposal in this docket, the Commission is contemplating the possibility of utilizing the alternative fuel test promulgated under the authority of section 401 of the NGPA for purposes of the incremental pricing program. The Commission presently has in place an interim rule which sets forth an alternative fuel test for purposes of the Commission's curtailment program. Although the Commission believes it has insufficient information upon which to base a decision to make that test immediately applicable to all agricultural uses within the incremental pricing program, the Commission believes, subject to further analysis, the alternative fuel test in place for the curtailment program may in fact be very appropriate for adoption in the incremental pricing program.

That test states essentially that if an end-user has utilized coal or residual fuel oil at any time since 1973, it is deemed to have alternative fuel capability. The rule was based on the belief that No. 2, or distillate oil, would not be reasonably available during the 1979 winter heating season.

One factor which must be considered in reaching a determination as to whether to utilize the curtailment program test for purposes of the incremental pricing program is that the class of agricultural uses within the incremental pricing program is much broader than that encompassed by the curtailment program. Another point which merits serious consideration is whether the economic practicability of potential alternative fuels can be determined on the basis of the same criteria for both programs.

The Commission will issue a proposal at a future date setting forth in detail its proposed alternative fuel test to be used for purposes of the incremental pricing program. Public comments will be requested on that proposal before any

final action is taken to apply the test to any agricultural user.

V. Effective Date

The rule below is being referred to the Congress for its review in accord with the provisions of section 206(d) of the NGPA. If neither House of Congress votes to disapprove of the rule, it will take effect following 30 days of continuous session of the Congress, as calculated in accord with section 507(b) of the NGPA.

(Natural Gas Policy Act of 1978, Pub. L. 95–621, 92 Stat. 3350, 15 U.S.C. 3301, *et seq.*)

In consideration of the foregoing, if neither House of Congress passes a Resolution of Disapproval of the regulation transmitted to them in this order, Part 282 of Subchapter I, Chapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective upon the expiration of 30 days of Congressional review, as described in section 507(b) of the NGPA.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,159]

45 F. R. 33603 (May 20, 1980)

18 CFR Part 292

[Docket No. RM79–54; Order No. 70–A]

Small Power Production and Cogeneration Facilities; Amendment to Final Rule Providing that Applications for Commission Certification of Qualifying Status Contain a Notice for Publication in the Federal Register

May 5, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) hereby adopts an amendments to its final rule implementing Section 201 of the Public Utility Regulatory Policies Act of 1978 (PURPA). The amendment provides that applications for Commission certification of qualifying status by cogenerators and small power producers pursuant to the rules implementing Section 201 of PURPA contain a notice for publication in the Federal Register.

EFFECTIVE DATE: May 5, 1980.

FOR FURTHER INFORMATION CONTACT: Deborah Gottheil, Office of the General Counsel, 825 North Capitol St., N.E., Washington, D.C. 20426, (202) 357–8457.

On March 13, 1980, the Federal Energy Regulatory Commission (Commission) issued Order No. 70, containing final regulations implementing section 201 of the Public Utility Regulatory Policies Act of 1978 (PURPA). (45 FR 17959, March 20, 1980).

These regulations set forth procedures by which certain small power production and cogeneration facilities can become "qualifying facilities" and thus be eligible for the rate benefits and exemptions from federal and State regulation set forth in the Commission's rules in Docket No. RM79–55 implementing section 210 of PURPA (45 FR 12214, February 25, 1980).

Section 292.207(b) of the regulations implementing section 201 of PURPA establishes an optional procedure whereby facilities may apply to this Commission for certification of qualifying status. The Commission is amending § 292.207(b) by adding a new paragraph providing that each application for certification by the Commission must include a notice describing the application for publication in the Federal Register. The notice should state the name of the applicant, the date of the application, and a brief description of the facility for which the qualification is sought, including a statement indicating whether the facility is a small power production facility or cogeneration facility, the primary energy source used or to be used by the facility, the power production capacity of the facility and its location.

The amendment provides a standard format which should be followed, including a paragraph providing interested persons with information as to how and when they may inform the Commission as to any interest they may have in the proceeding.

EFFECTIVE DATE: The Commission has already received several applications for certification, and therefore believes good cause exists under 5 U.S.C. 553(d) to make this amendment effective immediately.

(Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 2601, *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. 791 *et seq.*, Federal Power Act, as amended, 16 U.S.C. 792 *et seq.*, Department of Energy Organization Act 42 U.S.C. 7101 *et seq.*, E.O. 12009, 42 FR 46267, Natual Gas Policy Act of 1978, (15 U.S.C. 3301, *et seq.*))

In consideration of the foregoing, Part 292 of Chapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,160]

45 F. R. 33958 (May 21, 1980)

18 CFR Part 292

[Dockets Nos. RM79-54 and RM79-55]

Small Power Production; Order Granting in Part and Denying in Part Rehearing of Orders Nos. 69 and 70, and Amending Regulations

Issued: May 15, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Order granting in part and denying in part rehearing of order Nos. 69 and 70, and amending regulations.

SUMMARY: The Federal Energy Regulatory Commission (Commission) hereby adopts an order granting in part and denying in part petitions for amendment of Order Nos. 69 and 70. The Order amends four sections of the Commission's rules involving small power production. The amendments involve the definition of "total energy input," general requirements for qualification of new dual-fuel cogeneration facilities, fuel use criteria for qualifying small power production facilities, and the exemption of qualifying facilities from sections 19 and 20 of the Federal Power Act.

EFFECTIVE DATE: May 15, 1980.

FOR FURTHER INFORMATION CONTACT:

Adam Wenner, Office of the General Counsel, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8338, or

Glenn Berger, Office of the General Counsel, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8364.

SUPPLEMENTARY INFORMATION:

In the matter of Small Power Production and Cogeneration Facilities—Rates and Exemptions, Qualifying Status; order granting in part and denying in part rehearing of order Nos. 69 and 70, and amending regulations.

On February 19, 1980, the Federal Energy Regulatory Commission (Commission) issued Order No. 69, the "Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978" (PURPA) in Docket No. RM79-55.[1]

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[1] 45 *Fed. Reg.* 12214 (February 25, 1980).

The Commission received six applications for rehearing or reconsideration.[2]

On March 13, 1980 the Commission issued, in Docket No. RM79–54, Order No. 70, the "Final Rule Establishing Requirements and Procedures for a Determination of Qualifying Status for Small Power Production and Cogeneration Facilities."[3] That rule established criteria and procedures whereby small power production and cogeneration facilities could determine if they were eligible to receive the rate benefits and exemptions set forth in the Commission's rules implementing section 210 of PURPA.

The Commission received four petitions for rehearing of Docket No. RM79–54.[4]

With the exception of arguments discussed below, these applications raised no new matters of fact or law.

Order No. 69

Interconnection § 292.303(c). Consolidated Edison Company (Con Ed), Boston Edison Company, and Edison Electric Institute (EEI) recommended that the Commission determine that the interconnection procedures set forth in sections 210 and 212 of the Federal Power Act (FPA) are applicable to qualifying facilities, rather than requiring electric utilities to interconnect with a qualifying facility as an act included within the obligation to purchase, and not requiring an evidentiary hearing and the rendering of certain findings required under sections 210 and 212 of the FPA. In the final rule, the Commission observed that section 212(e) of the FPA provides that no provision of section 210 of the FPA should be treated as an exclusive means of obtaining relief.[5] The Commission interpreted this provision to mean that the existence of any authority under section 210 of the FPA to require interconnection should not be interpreted as exclusive of any other interconnection authority available under any other law. The Commission interpreted section 210(a) of PURPA as providing a broad grant of authority to prescribe rules necessary to encourage cogeneration and small power production, including the authority to require interconnection.

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[2] Southern Company Services, Inc. (March 14, 1980), Essex Development Association (March 14, 1980), American Electric Power Service Corporation (March 14, 1980), Edison Electric Institute (March 20, 1980), Consolidated Edison Company and Boston Edison Company (March 20, 1980), and Colorado-Ute Electric Association, Inc. (April 11, 1980).

The Commission notes that, while there is no express statutory right to rehearing of rules issued under section 210 of PURPA, there is a statutory right to rehearing of rules issued under section 201 of PURPA, which amended the Federal Power Act (FPA) by adding sections 3(17)–3(22). The Commission's view is that Congress, in incorporating by reference the enforcement provision of the Federal Power Act (Section 210h of PURPA), intended also to incorporate by reference the rehearing and judicial review provision of the Federal Power Act.

In addition, a case involving the Natural Gas Act and the Natural Gas Policy Act of 1978, the Court observed that

> * * * it is often not possible to draw a precise line separating the boundaries of the two Acts. Implementation of many NGPA Provisions requires conduct by FERC authorized under both Acts. As a result, the promulgation of rules may entail the exercise of authority under both the NGA and the NGPA. *Ecee, Inc. v. Federal Energy Regulatory Commission*, 611 F.2d 554, 564–566 (5th Cir. 1980).

The Commission notes that section 210 of PURPA and sections 3(17)–3(22) of the FPA, as added by section 201 of PURPA, are, to a large extent, interrelated. Section 201 of PURPA establishes the criteria and procedures by which a cogeneration or small power production facility can become a "qualifying" facility; section 210 of PURPA establishes rates for sales and purchases of electric power between qualifying facilities and electric utilities, and exempts qualifying facilities from certain State and Federal regulation. The relationship between the FPA and PURPA in this proceeding is thus similar to that between the NGA and the NGPA. For the reasons set forth in *Ecee*, the issues will be more clearly delineated, and the task of separating interrelated sections will be obviated, if these rulemakings are subject to review in the same forum. The Commission expects that any review of its order on rehearing in Docket Nos. RM79–54 and RM79–55, would occur in the Courts of Appeal, pursuant to section 313(b) of the FPA.

[3] 45 FR 17959 (March 20, 1980).

[4] Southern Company Services, Inc. (April 11, 1980), Consolidated Edison Company (April 14, 1980), Southern California Gas Company (April 14, 1980), Elizabethtown Gas Company (April 14, 1980).

[5] Section 212(e) of the FPA states that no provision of section 210 of the FPA shall be treated "(1) as requiring any person to utilize the authority of such section 210 or 211 in lieu of any authority of law, or (2) as limiting, impairing, or otherwise affecting any other authority of the Commisson under any other provision of law.

In their application, Con Ed and Boston Edison argued that the fact that Congress prohibited the Commission from exempting any qualifying facility from the provisions of sections 210 or 212 of the FPA renders moot or irrelevant the express ability of the Commisison to resort to other authority to require interconnections. They state that while section 210(a) of PURPA provides the FERC with a broad mandate to prescribe rules as it determines necessary, the Congress, in section 210(e) specifically prohibited the Commission from exempting any qualifying facility from the provisions of sections 210 or 212 of the FPA. As a result, Con Ed and Boston Edison claim that to read section 210(a) of PURPA as granting the "very authority specifically denied in section 210(e) of PURPA is to render the latter subsection utter surplusage."

The primary question arising from these claims is the proper interpretation of section 210(e)(3)(B) of PURPA, which provides that qualifying facilities cannot be exempted from sections 210, 211, and 212 of the FPA.

Section 210 of the FPA grants to electric utilities, Federal power marketing agencies, and qualifying congenerators any small power producers the right to apply for a Commission order requiring interconnection. The "target" of such an interconnection order can be "any cogeneration facility, and small power production facility, or the transmission facilities of any electric utility."[6]

Thus, in the procedures set forth in sections 210 and 212 of the FPA, qualifying facilities may either be applicants for interconnection orders, or targets of such interconnection orders. These sections confer upon qualifying facilities the right to apply for interconnection orders; they also impose on qualifying facilities the obligation and liability to be subjected to interconnection orders.

Section 210(e) of PURPA sets forth categories of State and Federal laws from which qualifying facilities can be exempted. The intent of this exemption is to remove the burden associated with being subjected to regulations as an electric utility under the FPA, the Public Utility Holding Company Act, and State laws regulating rates and financial organizations of electric utilities. The Joint Explanatory Statement of the Committee of Conference (Conference Report) accompanying PURPA states that rate regulation of qualifying facilities is to be done in a "less burdensome manner than traditional utility-rate regulation."[7] It further notes that

> [t]he establishment of utility type regulation over (cogeneration and small power production facilities) would act as a significant disincentive to firms interested in cogeneration and small power production.[8]

Thus, by exempting qualifying facilities from this type of regulation, Congress relieved them from liabilities and requirements to which others (*viz.*, non-qualifying facilities) are subject. Use of the word "exempt" in this context is consistent with its definition: "to release or deliver from some liability or requirement to which others are subject."[9] To "exempt" qualifying facilities does not mean to deny them a privilege or right to which they would otherwise be entitled; to exempt means to relieve of undesirable responsibility or obligation.

Sections 210 and 212 provide that, if the Commission makes certain determinations, it can impose obligations on qualifying facilities, including requiring the physical connection of the qualifying facility with the applicant, the sale or exchange of electric energy, or an increase in transmission capacity necessary to carry out these provisions. The Commission believes it is from these obligations that section 210(e)(3)(B) provides that qualifying facilities may not be exempted. Unlike the interpretation proffered by Con Ed and Boston Edison this reading comports with the plain meaning of the statute and with the accepted use of the language. And because qualifying facilities remain liable to being a target to an order under sections 210 and 212 of the FPA, section 210(e)(3)(B) is not "reader[ed] utter surplusage."[10]

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[6] Section 210(a)(1)(A), Federal Power Act.

[7] Conference Report in H.R. 4018, Public Utility Regulatory Policies Act of 1978, H.R. Rep. No. 1750, 95th Cong., 2d Sess. 97 (1978).

[8] *Id.*

[9] Webster's Third New International Dictionary (1976).

Under Con Ed's and Boston Edison's reading, section 210(e)(3)(B) of PURPA would also mean that qualifying facilities may not be exempted from applying under section 210 of the FPA to the Commission for an order requiring interconnection. The Commission notes that the ability to *apply* for an interconnection order is not a duty, liability, or requirement to which a qualifying facility is subject; it is a grant of standing to request the Commission to impose an obligation on another party (viz., a target of an interconnection order).[11]

Under Con Ed's reading, the Commission may not "exempt" a qualifying facility from this statutory privilege. Since, as noted previously, to exempt means to relieve of liabilities, and not be excluded from rights or privileges, this interpretation does not seem consonant with the plain meaning of the statutory language.

Transmission § 292.303(d). Southern Company Services, Inc. (Southern Company), stated that § 292.303(d) appears to prohibit an electric utility transmitting from a qualifying facility to another electric utility from levying a transmission charge. This interpretation is not the one intended by the Commission. The sentence in question states that "[t]he rate for purchase by the electric utility to which such energy is transmitted * * * shall not include any charges for transmission." This phrase is intended to limit the amount that the utility to which electric energy is ultimately delivered must pay. This sentence provides that the purchasing utility need purchase this energy at a rate which reflects the costs it can avoid as a result of making such a purchase, and that any costs incurred to deliver the energy to it are the responsibility of the selling qualifying facility. (The transmitting utility may, however, agree to bear some or all of the transmission costs.)

The Commission does intend that an electric utility which *transmits* energy from a qualifying facility to another electric utility be permitted to receive reimbursement for this transmission service. As noted by Southern Company Services, this intent is expressed in the preamble, where the Commission stated:

> In the case of electric utilities not subject to the jurisdiction of this Commission, these (transmission) charges should be determined under applicable State law or regulation which may permit agreement between the qualifying facility and any electric utility which transmits energy or capacity with the consent of the qualifying facility. For utilities subject to the Commission's jurisdiction under Part II of the Federal Power Act, these charges will be determined pursuant to Part II.[12]

Southern Company recommends that these provisions be added to section 292.303(d), in place of the sentence which provides that rates for purchases shall not include any charges for transmission. The Commission believes that the provision as issued is acceptable. With this clarification, the proper interpretation should be clear.

Exemptions § 292.601(b). On March 19, 1980, Essex Development Associates

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[10] Petition for Rehearing and Reconsideration, Con Ed and Boston Edison, *supra* note 1, *mimeo* at 6.

[11] Indeed, the ability to apply for an order imposing an obligation to wheel or transmit power was not conferred upon qualifying facilities; thus exclusion from being an applicant is an important distinction between sections 210 and 211 of the FPA.

[12] Order No. 70 *supra*, *mimeo* at 32.

(Essex) filed a Motion for Clarification of Order No. 69. Essex observed that the Commission did not exempt qualifying facilities from sections 19 and 20 of the Federal Power Act (FPA or Act). Essex stated that these sections provide the Commission with discretionary jurisdiction to regulate rates and the issuance of securities by licensees under Part I of the Federal Power Act. Essex contends that the intent of section 210 of PURPA and of Order No. 69, is to eliminate utility-type regulation of cogenerators and small power producers, without regard to the status of the facility as a licensee under Part I of the Federal Power Act. Essex requests that the Commission amend Order No. 69 to exempt qualifying facilities from sections 19 and 20 of the FPA, or that the Commission waive its rights under sections 19 and 20 to regulate a qualifying small power producer.

It should be noted that section 210(e)(3)(C) of PURPA provides that no qualifying facility may be exempted from

> * * * any license or permit requirement under Part I of the Federal Power Act, any provision under such Act related to such a license or permit requirement, or the necessary authorities for enforcement of any such requirement.

The threshold question is whether this section should be interpreted to prevent the exemption of qualifying facilities from sections 19 and 20 of the Federal Power Act.

The intent of section 210(e) of PURPA, and of § 292.601 of the Commission's regulations (exemption to qualifying facilities from the Federal Power Act), is to remove the disincentive associated with utility-type regulation.[13] In Order No. 69, the Commission exempted qualifying facilities from cost-of-service regulation of rates, and from regulation of securities to which jurisdictional public utilities are subject under Part II of the Federal Power Act. In addition, within the statutory parameters, the Commission exempted qualifying facilities from regulation as electric utilities under the Public Utility Holding Company Act, and from State regulation of rates and financial organization.

Regulation under Part II of the Federal Power Act chiefly involves regulation of rates and financial organization, while regulation under Part I of the Act concerns the licensing of hydroelectric projects. A licensed project under Part I of the Federal Power Act may also be a qualifying small power producer, if it meets the size and ownership requirements set forth in Order No. 70.[14]

In pertinent part, section 19 of the Federal Power Act provides that, as a condition of a license, a licensee "developing, transmitting, or distributing power for sale or use in public service," shall abide by the rate and service regulation of any duly constituted agency of the State in which such service is provided. If power is provided in a State in which there is no authorized regulatory commission to regulate the rates for sales of power, or the issuance of securities by a licensee, jurisdiction is conferred on the Commission to regulate these matters.

Section 20 of the FPA provides that, with regard to power from a licensed project that enters interstate or foreign commerce, the rate charged shall be "reasonable, nondiscriminatory, and just to the customer," and all "unreasonable discriminatory and unjust rates" are prohibited. It provides that if any State affected has not established a commission to enforce these requirements, or to regulate the issuance of securities, or if any parties or States are unable to agree on appropriate regulation, jurisdiction is conferred on the Commission to regulate these activities.

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[13] Conference Report in H.R. 4018, Public Utility Regulatory Policies Act of 1978, H.R. Rep. No. 1750, 95th Cong., 2nd Sess. 98 (1978).

[14] Section 292.206 of the Commission's rules provides that a facility cannot qualify if more than 50 percent of the equity interest in the facility is held by an electric utility or utilities, or public utility holding companies. Section 292.204(a) provides that the power production capacity of a qualifying facility may not exceed 80 megawatts. Pursuant to § 292.601 (Order No. 69), only small power production facilities of 30 mw or less are exempted from the Federal Power Act, the Public Utility Holding Company Act, and State regulation, except biomass facilities between 30 and 80 megawatts, which are exempt from State regulation and from the Public Utility Holding Company Act.

The Commission observes that most of the provisions of Part I of the Act impose conditions and restrictions on the construction and operation of hydroelectric facilities, which require that licensed projects comply with comprehensive development of the nation's waterways. As a result, the Commission perceives no inconsistency in exempting licensed projects that are qualifying facilities from State and Federal regulation of rates and financial organization, and maintaining Federal regulation of the physical structure of such facilities, and their manner of operation. The Commission believes that the limitation on exemption from the Federal Power Act set forth in section 210(e)(3)(C) of PURPA was intended to ensure that licensees comply with the requirements concerning comprehensive development of waterways, and ensure that they do not build or operate hydroelectric projects in a manner inconsistent with the public interest.

Nowhere in the legislative history of section 210, or in the Conference Report, does there appear any indication that qualifying facilities that are licensed hydroelectric projects were intended to be singled out for utility-type rate or securities regulation. To subject these licensed projects to such regulation would be inconsistent with the intent of this section of PURPA—to encourage cogeneration and small power production. Thus, the Commission finds no basis to subject small power producer licensees to regulation under sections 19 and 20 of the Act, when they would otherwise be exempted from utility-type regulation at both the Federal and State levels.[15]

Moreover, the Commission finds no basis to believe that section 210 of PURPA was intended to grant exemption from the regulations of rates and financial organization, and yet to retain the authority to impose regulation of rates and the issuance of securities for one class of small power producers.

Rules of statutory construction indicate that the Commission should look to the object to be accomplished, and the evils sought to be remedied.[16] Moreover, a statute should be construed so as to effect its purpose.[17] The Commission has cited the reference in the Conference Report regarding its disincentives associated with "utility type regulation." It further cites the Conference Report statement that

> [I]t is not the intention of the conferees that cogeneration and small power producers become subject * * * to the type of examination that is traditionally given to electric utility rate applications to determine what is the just and reasonable rate that they should receive for their electric power.[18]

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[15] The Commission observes that even if exemption from these provisions were not granted, the residual grant of authority to the Commission set forth in sections 19 and 20 is consistent with the rate and exemption provisions of section 210 of PURPA, and with Order No. 69. Section 210(b) provides that rates for purchases from qualifying facilities shall be "just and reasonable to the electric consumers of the electric utility and in the public interest, and shall not discriminate against qualifying facilities." Section 292.304(a) repeats these statutory requirements. Section 210(f) of PURPA and § 292.401 of the Commission's rules require that, within one year after the Commission's rules take effect, each State regulatory authority is to implement the rules issued by the Commission regarding rates for purchases and sales of electric energy and capacity between qualifying facilities and electric utilities. After State implementation takes place, compliance with section 19—whether viewed as State regulation in the first instance or residual Federal regulation—would be accomplished through the State's program implementing section 210 of PURPA, and Order No. 69. Similarly, the requirements set forth in section 20 regarding the rates for power from licensed projects are not inconsistent with the requirements of section 210 of PURPA, or Order No. 69. Again, regulation under section 210 of PURPA would constitute the vehicle for regulation under section 20 of the Act. (For qualifying small power production facilities greater than 30 mw, where the facility is subject to Commission jurisdiction under Part II of the Federal Power Act, the Commission will establish rates for purchase in accordance with the avoided cost principles set forth in § 292.304.)

[16] 82 C. J. S. *Statutes* § 323.

[17] *Id.*

[18] Conference Report, *supra* note 13, at 97.

The authority contained in sections 19 and 20 of the Federal Power Act would reserve to the Commission the authority to impose this type of utility regulation on qualifying small power producer licensees. The possibility that such regulation will be imposed could reduce the encouragement of development of small power production which the Congress, in section 210 of PURPA, and the Commission, in Order No. 69, intended to provide. For the reasons set forth, the Commission finds it appropriate to exempt qualifying facilities from these sections of the Federal Power Act.

Accordingly, the Commission amends § 292.601(b)(1), so as to exempt qualifying facilities from sections 19 and 20 of the Federal Power Act.

Order No. 70

Definitions § 292.202. Sections 292.202(i) and 292.202(j), define the "total energy output" and "total energy input" of a qualifying facility. Dividing the total energy output by the total energy input indicates the efficiency of the facility.

In § 292.202(j) of the final rule, energy obtained from supplementary firing was inadvertently excluded from the definition of total energy input. Since energy from supplementary firing was not excluded from the definition of total energy *output*, the rule would distort the efficiency of facilities in which large amounts of energy are supplied from supplementary firing, making them appear more efficient than they are.

To correct this unintended result, the Commission is amending the definition of total energy input so that it includes energy supplied from supplementary firing. This change will be accomplished by deleting the clause "other than supplementary firing" from the definition of total energy input.

Ownership § 292.206(b). Southern California Gas Company (SCGC) and Elizabethtown Gas Company (Elizabethtown) contend that § 292.206(b) of the Commission's rules erroneously exclude from qualifying status facilities owned by public utility holding companies that are not engaged in the generation or sale of electricity other than from cogeneration facilities or small power production facilities. Elizabethtown states that the rules do not prohibit a gas distribution utility from owning a qualifying facility.

Sections 17(C)(ii) and 18(B)(ii) of the Federal Power Act require the Commission to limit qualifying status to facilities "owned by persons not primarily engaged in the generation or sale of electric power." Section 292.206 of the Commission's rules prohibits public utility holding companies from owning more than 50 percent of the equity interest of a qualifying facility.

The Commission did not intend to prohibit companies without any electric utility interests from owning qualifying facilities. However, because public utility holding companies are subject to many special restrictions, before changing this provision of its rules, the Commission believes it appropriate to consult with the Securities and Exchange Commission to determine whether permitting gas holding companies to own qualifying facilities is consistent with that agency's regulation of holding companies.

Fuel Use § 292.204(b)(1). Southern Company takes exception to the fuel use criteria employed by the Commission in defining a qualifying small power production facility under § 292.204(b) of the rules. In the proposed rule, the term "primary energy source" was not defined. In response to several comments that standards should be established for determining the primary energy source, the Commission required in § 292.204(b)(1) of the final rule that more than 50 percent of the total energy input of a qualifying facility be from biomass, waste, renewable resources, or any combination thereof.

Southern Company states that a small power production facility which utilizes biomass, waste, or renewable resources as its "primary energy source" no more than 51 percent of the time, complies with the "sole" use requirement of the PURPA definition. Southern Company contends that this standard should be eliminated in favor of a standard which requires a small power production facility to use a higher percentage of renewable resources, waste, or biomass.

Two provisions of the rules are involved in this issue. Section § 292.204(b)(2) provides that the oil, natural gas, and coal used by a qualifying facility may not, in the aggragate, exceed 25 percent of the total energy imput of the facility during any calendar year. As discussed in the preamble [19] comments received indicated that effective use of biomass or waste as fuels can require that as much as 25 percent of the heat input be from fossil fuel. To assure that these renewable resources qualify for the statutory benefits, the Commission adopted the "25 percent rule."

As noted above, § 292.204(b)(1)(i) provides that more than 50 percent of the total energy input to a qualifying small power production facility must be biomass, waste, renewable resources, or any combination thereof.

At this time, the Commission believes that there are virtually no eligible fuels which are feasible for use by a qualifying facility to fill the hiatus if it derives 50 percent of its energy input from biomass, waste or renewable reosurces, and 25 percent from oil, natural gas and coal. The Commission will accordingly amend this provision of its rule to require that at least 75 percent of the total energy input of a qualifying small power production facility be from biomass, waste, renewable resources, or any combination thereof.

§ 292.204(b)(2). Southern Company also contends that the Commission's 25 percent limit on fossil fuel use by qualifying facilities is too broad, and is inconsistent with national energy policy. Southern Company argues that the Commission should adopt individual standards for each category of fossil fuel use listed in section 201 of PURPA, as appeared in the notice of proposed rulemaking.[20]

The Commission rejects this petition. The Commission based the 25 percent standard on the comments filed which generally favored a uniform aggregate standard. Commenters argued that separate standards for startups, flame stabilization and outages are unnecessarily burdensome. They also claimed that some small power production technologies would be severely constrained by one of the standards while requiring little or no fossil fuel for other purposes. Additionally, the Commission belives that to the extent oil and natural gas remain more expensive than other energy sources available to small power producers, there is an economic disincentive to use more fossil fuel than is absolutely necessary.

Southern Company stated that the Commission's rules are inconsistent with standards promulgated under the Powerplant and Industrial Fuel Use Act of 1978 (FUA). The Commission notes that the FUA is intended to encourage the burning of coal in conventional power plants and industrial fuel burning plants. In contrast, sections 201 and 210 of PURPA are intended to encourage the cogeneration and electric generation through the use of biomass, waste, and renewable resources. Coal may not be used by a qualifying small power production facility as a primary energy source. Southern Company argues that the Commission should adopt, in its rules, the definition of "primary energy source" set forth in the interim rules implementing the FUA. These rules provide that a facility's consumption of oil and gas may not exceed five percent of the facility's annual Btu output. While the use of five percent gas or oil may be sufficient in combination with coal fuel, the burning of biomass or waste can require a greater use of gas or oil. Comments indicate that if the Commission were to adopt the more stringent five percent standard, the operation of many of these energy sources would not be feasible.

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[19] Order No. 70, *supra*, mimeo at 38–40.

[20] These categories include fuel used for ignition, startup, testing, flame stabilization, and control uses, and fuel used to alleviate or present unanticipated equipment outages and emergencies that would affect public health, safety or welfare. Section 3(17)(B), FPA.

Consequently, the Commission does not find that its rules are inconsistent with FUA standards, and rejects this proposed revision of the rules.

§§ *292.203(b) and 292.205.* Southern Company and Con Ed submit that the Commission's rules are inconsistent with national energy policy in that they allow cogeneration facilities to burn oil and natural gas. Both petitioners request that the Commission amend its rules to include fuel use criteria for cogeneration facilities which the Commission determines to be qualifying cogeneration facilities. The result, they contend, of the Commission's failure to include fuel use restrictions is to authorize the burning of oil or natural gas for generation of electricity in cogeneration units, which will displace electricity generated by coal, nuclear or hydro power.

Numerous comments on this issue were submitted during the rulemaking process. First, the Commission notes that these rules do not authorize any facility to burn oil or gas in contravention of any applicable Federal, State or local laws or regulations. Rather, their effect is to make facilities, some of which may be authorized to burn fossil fuels under other statutory authority, such as the FUA, eligible for the rate and exemption privileges set forth in section 210 of PURPA.

As noted in the preamble [21] the Commission believes that the legislative history, Congressional intent, and national energy policy support the use of oil and gas in cogeneration facilities. Section 206(c)(3) of the Natural Gas Policy Act, authorized the Commission to exempt gas used by qualifying cogeneration facilities from incremental pricing surcharges.

Furthermore, the Commission believes that economics will make the displacement of nuclear coal or hydro generated electricity by a cogenerator using oil or natural gas a rare occurrence. In most cases, electricity generated by a cogenerator using oil or gas fuels is more expensive than electricity generated by nuclear, coal or hydro facilities. As a result, market forces, rather than an additional layer of Federal fuel use regulation, can effectively determine the appropriate use of oil or gas. For the above reasons the Commission denies the petition for amendment of this section of the rule.

Notice § 292.207. Southern Company and Con Ed petitioned the Commission to amend § 292.207 of its rules. This provision requires all qualifying facilities to furnish notice to the Commission of their status as qualifying facilities, and to provide a brief description of the facility and other pertinent data. The petitioners requested that the Commission require an applicant for certification of qualifying status intending to interconnect with a utility to furnish notice to the appropriate State regulatory authority and the utility with which it would interconnect.

The Commission has recently amended § 292.207(b)(6) of its rules. [22] This amendment requires that all applications for Commission certification of qualifying status include a notice of such request for publication in the Federal Register. The Commission believes that publication will provide adequate notice of applications for qualifying status. The Commission, therefore, rejects the petitions for amendment of § 292.207 of its rules.

Southern Company also petitioned the Commission to amend § 292.207(c) of the rule. This paragraph states that an electric utility is not required to purchase electric energy from a qualifying facility of 500 kilowatts or more until 90 days after the facility notifies the utility that it qualifies, or that it has applied to the Commission for qualification. Southern Company contended that this section implies that a utility is derelict if it does not begin purchasing power from a qualifying facility over 500 kilowatts within 90 days after the facility has notified the utility or applied to the Commission for certification as a qualifying facility. Southern Company believes that 90 days is not a sufficient time period in which it can adjust its system to receive the generation output of the qualifying facility. Southern Company requested amending § 292.207(c) to allow for a "reasonable time" in which it must begin purchasing power from a qualifying facility.

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[21] Order No. 70, *supra, mimeo* at 24–26.

[22] Amendment to Final Rule Providing That Applications For Commission Certification of Qualifying Status Contain a Notice for Publication in the Federal Register, Order No. 70-A, Docket No. RM79-54, May 5, 1980.

Southern Company has erroneously interpreted § 292.207(c). Section 292.207(c) must be read in conjuction with § 292.207(b)7 and § 292.306. These sections provide that a utility is required to purchase power from a qualifying facility only if the facility meets all safety requirements, and pays for the appropriate interconnection costs as determined by the State regulatory authority. The 90-day requirement set out in § 292.207(c) establishes a minimum time period in which a utility must purchase power from a qualifying facility which has met all other applicable safety and interconnection requirements of the regulations. A utility need not purchase power from a qualifying facility until it meets these requirements, even if the 90-day period has elapsed. The Commission believes this interpretation of the regulation allows for a reasonable time period in which a utility must purchase power from a qualifying facility. Therefore, the Commission rejects the petition for amendment of this section.

Procedures for Obtaining Qualifying Status § 292.207. Con Ed states that the self-certifying procedure for obtaining qualifying status fails to inform utilities whether a particular facility is qualified. Under the proposed rule, all determinations of qualifications would have required Commission action on a case-by-case basis. Comments received indicated that when no affected party questions the eligibility of a facility, there is no need to require filing for qualification. As noted in the preamble to Order No. 70, the initiation of negotations concerning purchase and sale arrangements allows for the flow of information between potential qualifying facilities and affected electric utilities.[23] If a utility considers that a facility does not qualify, it is not obligated to purchase its electric output.

In such cases, the facility may seek Commission certification under § 292.207(b). The Commission expects that, for the great majority of facilities requesting that utilities purchase their electric output, there will be no disagreement as to their eligibility. In questionable cases, the rules as issued provide for Commission determination of the facility's status. Thus, the Commission perceives no need to require additional paperwork in uncontested determinations.

§ *292.206(d)*. Con Ed requested that the Commission amend § 292.206(d) to include a mechanism for monitoring facilities to assure that the requirements for obtaining qualifying status continue to be met.

The Commission believes that the administrative costs associated with monitoring large numbers of qualifying facilities would be prohibitive. The Commission notes that section 201 of PURPA amended the Federal Power Act, and that these rules fall under the ambit of the enforcement provisions of sections 314 and 316 of the FPA. Under these provisions, an applicant that ceases to meet the requirements for qualifying status, and fails to notify the Commission pursuant to § 292.207(d)(2) may be subject to civil and criminal penalties. The Commission will investigate any complaints that qualifying requirements are not being met. As a result, the Commission believes it is not necessary to establish a monitoring system.

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[23] Order No. 70, *supra*, *mimeo* at 19.

[24] Notice of No Significant Impact and Notice of Intent to Prepare Environmental Impact Statement, issued March 31, 1980, Docket No. RM79-54, *mimeo* at 44.

Environmental Effects § 292.203(c). In the Environmental Assessment (EA) issued with Docket No. RM79-54 [24], the Commission determined that the incentives provided in this program will encourage the development of only one technology, commercial cogeneration primarily by new diesel engines, at a level where significant environmental effects may occur in the near-term. Con Ed contended that spark ignition and dual-fuel cogeneration engines will also be widely used in commercial applications and will produce a substantial environmental impact.

Con Ed's petition does not refer to the discussion contained in the Appendices to the EA, referred to in the Commission's Notice accompanying the EA. In Appendix C the Commission stated:

> Dual-fuel engines and diesel engines are likely to be the primary equipment choice for commercial cogeneration. Combustion turbines are large (greater than about 1 MW) and cost about $900 to $1,000/Kw. Thus, investors would be facing equipment costs of about $1,000,000 to install one of these units.
>
> Spark ignition engines (similar to large gasoline-fuel truck engines) are insufficiently sturdy to warrant their use in continuous duty cogeneration. Despite the low capital costs for spark ignition engines compared with those for diesel engines, repair and maintenance costs for the former are substantially higher.
>
> Commercial cogeneration users will use natural gas as a fuel for dual-fuel engines whenever gas is available or less expensive than diesel fuel. In rural areas and in some urban areas of the Middle Atlantic region, natural gas is not available and distillate fuel use is expected. Thus, in these areas cogenerators will choose diesel engines. In large urban areas, because natural gas is available for potential cogenerators, cogenerators will install dual-fuel engines to take advantage of low-priced natural gas, even though a dual-fuel engine costs 20% to 30% more initially. We cannot precisely estimate the percent of the 2,500 MW of capacity that will be found in large urban areas. We estimate, however, that cogeneration in larger urban regions may account for 25 percent to 75 percent of the total.[25]

If gas is available for commercial or residential use in urban areas in the Middle Atlantic region, the installation of a great number of dual-fuel cogeneration engines in these areas might adversely affect the environment. Pending further environmental analysis, the Commission has decided to require that dual-fuel cogeneration facilities obtain qualification on a case-by-case basis, pursuant to the procedures set forth in section 292.207(b) of the Commission's rules. Before permitting new dual-fuel facilities to qualify, the Commission will consider the emission characteristics of the facility, and the number of qualifying cogeneration facilities in the vicinity of the applicant.

The Commission Orders: (A) To the extent not granted above, the applications for rehearing and reconsideration of Order Nos. 69 and 70 filed by Southern Company Services, American Electric Power Service Corporation, Edison Electric Institute, Consolidated Edison Company, Boston Edison Company, Colorado-Ute Electric Association, Inc., Elizabethtown Gas Company and Southern California Gas Company are denied.

(B) Sections 292.202, 292.203, 292.204, and 292.601 are amended as set forth below effective on May 15, 1980.

(Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 2601, *et seq.;* Energy Supply and Environmental Coordination Act, 15 U.S.C. § 791 *et seq.;* Federal Power Act, as amended, 16 U.S.C. § 792 *et seq.,* Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.;* E.O. 12009, 3 CFR 142 (1978))

In consideration of the foregoing, the Commission amends Part 292 of Chapter I, Title 18, Code of Federal Regulation, as set forth below, effective May 15, 1980.

By the Commission.

Kenneth F. Plumb,
Secretary.

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[25] EA, *supra,* Appendix C, *mimeo* at 7.

[¶ 30,161]

45 F. R. 34264 (May 22, 1980)

18 CFR Part 284

[Docket No. RM79-34, Order No. 30-B]

Transportation Certificate for Natural Gas for the Displacement of Fuel Oil

Issued: May 15, 1980

AGENCY: Federal Energy Regulatory Commission.

ACTION: Interim Rule and request for comments on extension.

SUMMARY: On May 12, 1980, the Economic Regulatory Administration (ERA) of the Department of Energy issued a proposal (published elsewhere in this issue) pursuant to section 403(a) of the Department of Energy Organization Act to extend the Commission's fuel oil displacement program for one year (Order No. 30). This program authorizes the transportation of natural gas to end users that would otherwise burn fuel oil. The Commission hereby establishes a public hearing and comment procedure on ERA's proposed rule. Furthermore, pending completion of the rulemaking proceeding in this docket, the Commission extends, on an interim basis, the Order No. 30 program for three months, *i.e.*, through August 31, 1980.

DATES: Effective date: May 15, 1980. Public Hearing on June 16, 1980. Notice of intent to participate in public hearing by June 9, 1980. Submission of statement for presentation of public hearing by June 13, 1980. Written comments filed by June 16, 1980.

ADDRESS: All filing should reference Docket No. RM79-34 and should be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street N.E., Washington, D.C. 20426.

Public hearing location: Address above beginning at 9:30 a.m.

FOR FURTHER INFORMATION CONTACT: Robert C. Platt, Office of the General Counsel, 825 North Capitol Street N.E., Washington, D.C. 20426 202-357-8454.

SUPPLEMENTARY INFORMATION:

I. Introduction

On May 17, 1979, the Federal Energy Regulatory Commission (Commission) issued Order No. 30 which established a short term program authorizing the transportation of natural gas for the displacement of fuel oil (44 FR 30323, May 25, 1979). That order was adopted in response to a proposal of the Economic Regulatory Administration (ERA) of the Department of Energy which was referred to the Commission pursuant to section 403(a) of the Department of Energy Organization Act, 42 U.S.C. § 7173(a) (DOE Act). (44 FR 17644, March 22, 1979) [1]

In Order No. 30, the Commission recognized that rapidly changing factors surround the fuel oil displacement program and was unable to conclude that the program would be necessary beyond June 1, 1980. The regulations in Order No. 30 reflect this determination by providing that the program remain in effect during a "fuel shortage emergency period" which expires on June 1, 1980.

On May 12, 1980, the ERA proposed a further rule under section 403(a) of the DOE Act which would extend the "fuel shortage emergency period" for an additional year.[2] the ERA proposal finds "that the urgent need to reduce oil imports still exists." For this reason, and because of the importance of fashioning a Commission regulation consistent with the overall ERA fuel oil displacement effort, the Commission seeks comment upon the ERA proposed extension as submitted.[3] In particular, the Commission invites comments on whether the program, if extended, should be limited to the displacement of premium grades of fuel oil such as low sulphur residual fuel oil and middle distillates.

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[1] In a related rule, the ERA established a procedure to certify the eligibility of end-users for this program. 10 CFR Part 595, 44 FR 20398 (April 5, 1979).

[2] The ERA proposal is being published in the Federal Register concurrently with the interim rule in this docket.

Section 403(a) of the DOE Act authorizes the Secretary of Energy to propose rules with respect to any function within the jurisdiction of the Commission. Section 403(b) of that Act provides that the Commission shall have exclusive jurisdiction over such proposals. Accordingly, although the appended proposal is that of the ERA, the rulemaking proceeding commenced by this order shall result in a final rule of the Commission, and shall be governed by the Commission's procedures.

II. *Interim Extension*

As noted above, the fuel shortage emergency period defined in Order No. 30 ends on June 1, 1980. Since the public procedures on the ERA proposal will not be completed by that date, the Commission would be unable to take final action on the ERA proposal prior to the expiration of the Order No. 30 program. For this reason, the Commission extends the fuel oil displacement program for an additional three months. Thus, this interim rule amends the definition of "fuel shortage emergency period" in § 284.201(e) of the Commission's regulations to extend the period through August 31, 1980.

Section 284.208(c)(2) is also amended to clarify that our delegation to the Director of the Office of Pipeline and Producer Regulation remains in effect during the extension.

III. *Written Comment Procedures*

Interested persons are invited to submit written comments, data, views, or arguments with respect to the ERA proposed rule and the interim extension of the Order No. 30 program. An original and 14 copies should be filed with the Secretary, June 16, 1980, will be considered by the Commission prior to promulgation of final regulations. All written submissions Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, and should reference Docket No. RM79-34. All comments received prior to 4:30 p.m. e.d.t., June 16, 1980, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection through the Commission's Division of Public Information, Room 1000, 825 North Capitol Street NE., Washington, D.C. during regular business hours.

IV. *Public Hearing Procedures*

A public hearing concerning the interim extension and ERA's proposal will be held at the Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. on June 16, 1980, beginning at 9:30 a.m. and will continue if necessary on the following day. Any person interested in this proceeding or representing a group or class of persons interested in this proceeding may make a presentation at the hearing provided a written request to participate is received by the Secretary of the Commission prior to 4:30 p.m. e.d.t., on June 9, 1980.

Requests should reference Docket No. RM79-34, and should indicate the amount of time, not to exceed fifteen minutes, that is required for the oral presentation, and the telephone number at which the person making the presentation can be reached. At least 14 copies of the statement shall be submitted to the Secretary of the

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[3] Consolidated Edison Company of New York, Public Service Electric and Gas, and National Fuel Gas Supply Corporation have filed motions in this docket seeking an extension of the program. Comments have also been filed, some in favor of and others in opposition to an extension. Furthermore, the Commission convened an informal conference on April 2, 1980, to study the nation's natural gas supply outlook. Notice of Informal Conference, Docket No. GP80-76, 45 FR 15944 (March 12, 1980).

Commission prior to 4:00 p.m. on June 13, 1980.

Persons participating in the public hearing should, if possible, bring 50 copies of their testimony to the hearing for distribution to other participants. A list of participants in the hearing will be available in the Commission's Division of Public Information, Office of Congressional and Public Affairs, three days before the hearing and will be available at the site of the hearing on the morning it is convened.

The hearing will not be a judicial or evidentiary-type hearing. Members of the hearing panel will be designated by the Chairman of the Commission. There will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested person may submit questions to the presiding officer to be asked of persons making statements. The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. Any further procedural rules will be announced by the presiding officer at the hearing. A transcript of the hearing will be available through the Commission's Division of Public Information.

V. *Effective Date*

The Commission finds that the public interest is best served by the continuation of the fuel oil displacement program pending the Commission's consideration of ERA's proposed rule. In order to accomplish this, the Commission must act before June 1, 1980. For this reason, the Commission finds good cause to waive the 30-day requirement set forth in 5 U.S.C. § 553(d) and to make this interim rule effective immediately.

(Natural Gas Act, 15 U.S.C. § 717 *et seq.;* Natural Gas Policy Act of 1978, P.L. 95–621; Department of Energy Organization Act, P.L. 95–91; E.O. 12009, 42 FR 46267)

In consideration of the foregoing, Part 284 of Chapter I, Title 18, Code of Federal Regulations, is amended, on an interim basis, as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,162]

45 F. R. 35322 (May 27, 1980)

18 CFR Part 274

[Docket No. RM79-3]

Determinations by Jurisdictional Agencies; Colorado Application for Alternative Filing Requirements

Issued: May 20, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: This rule adds § 274.208(a) to the Federal Energy Regulatory Commission Regulations implementing the Natural Gas Policy Act of 1978. The new section provides alternative filing requirements for certain well determination applications to the Colorado Department of Natural Resources' Oil and Gas Conservation Commission.

EFFECTIVE DATE: May 20, 1980.

FOR FURTHER INFORMATION CONTACT: Victor Zabel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357–8559.

SUPPLEMENTARY INFORMATION: On January 14, 1980, the Colorado Department of Natural Resources, Oil and Gas Conservation Commission (Colorado) filed an application with the Commission for approval of alternative filing requirements pursuant to § 274.207 of the Commission's regulations. The proposed alternative filing requirements would enable operators to apply for eligibility determinations under section 103 of the Natural Gas Policy Act of 1978 (NGPA) for additional wells in existing proration units in the Sussex and Shannon reservoir in the Spindle Field, and in the Sessex reservoir in the

Hambert Field, in Adams and Weld Counties, Colorado, without repeated submissions of geological and engineering data to show that the additional well is necessary to effectively and efficiently drain a portion of the reservoir covered by a proration unit that cannot be effectively and efficiently drained by any existing well within the proration unit.

Section 103 of the NGPA establishes the maximum lawful price for natural gas produced from new, onshore production wells. Under § 271.305(b) of the Commission's regulations, an additional well drilled on or after February 19, 1977, in an existing proration unit may qualify for the section 103 price if the jurisdictional agency finds that the well is necessary to effectively and efficiently drain a portion of the reservoir covered by the proration unit.

An applicant seeking a determination of eligibility under § 271.305(b) to collect the section 103 price is required to file with the appropriate jurisdictional agency the information specified in § 274.204 of the Commission's regulations. Under § 274.204(f), an applicant must submit, on a well-by-well basis, geological evidence and engineering data showing that an additional well within the existing proration unit is necessary to effectively and efficiently drain a portion of the reservoir covered by the proration unit, which cannot be effectively and efficiently drained by any existing well in the proration unit.

Under § 274.207, however, a jurisdictional agency is authorized to apply for Commission approval of alternative filing requirements. Colorado's application for approval of alternative filing requirements is based on those portions of Colorado's Order Nos. 304-5, 250-12, 250-14, 250-16, 250-17, 250-19, 250-20, 250-21, and 250-23 that authorize the drilling of additional wells into existing proration units in the Shannon and Sussex reservoirs in the Spindle Field, and in the Sussex reservoir in the Hambert Field, in Adams and Weld Counties, Colorado. In lieu of the filing requirements presently found in § 274.204(f), Colorado would simply require that the applicant file a statement specifying that the applicant is seeking a determination with respect to an additional well drilled into an existing proration unit and specifying the applicable order (from the orders mentioned above) which permitted the drilling of the additional well.

Colorado has concluded that the proposed alternative filing requirements provide substantial evidence on which to base a determination, since the pertinent geological and engineering data showing the necessity for second wells in existing proration units has already been accumulated during hearings under oath, based upon which the relevant orders were adopted. Colorado has furnished the pertinent geological and engineering data and other material which were offered into the record at the hearings concerning the above-mentioned orders in its application for approval of alternative filing requirements. Colorado asserts that this evidence is sufficient for all determinations involving wells drilled under the authority of these orders.

The Commission has review the geological and engineering data submitted by Colorado. The Commission finds that the proposed alternative filing requirements will provide sufficient information and substantial evidence upon which determinations under section 103 can be based. Accordingly, the Commission is amending Part 274, Subpart B, in § 274.208 to adopt the alternative filing requirements proposed by Colorado for applications for new, onshore production well determinations for second wells drilled into existing proration units pursuant to the above-mentioned orders.

The Commission's regulations in § 271.305(c) require jurisdictional agencies to notify the Commission when findings are made under § 271.305 that an additional well in an existing proration unit is necessary for effective and efficient drainage. Since Colorado's orders, listed above, find that infill drilling of additional wells in established proration units is necessary on a field-wide basis for the effective and efficient drainage of portions of the reservoirs covered by proration units which cannot be effectively and efficiently drained by an existing well within those units, the Commission finds that there is no need for Colorado to notify the Commission on an individual well basis that it has made the effective and efficient drainage finding for and individual well. Accordingly, for second wells drilled into existing proration units pursuant to the orders listed above, the Commission deems satisfied the requirements of § 271.305(b) and (c) with respect to determinations made by Colorado.

Further, § 274.204(d)(4) requires the filing of an oath statement that the applicant's conclusion that the natural gas for which he seeks a determination is produced from a new, onshore production well is based on documents submitted in the application. The oath statement must be modified for wells covered by the alternative filing requirements inasmuch as the applications will not contain all the documents relied on by the applicant in making the conclusion. Therefore, the phrase "documents submitted in the application" will be deleted from the oath statement, as applicable to persons seeking section 103 eligibility determinations for second wells drilled into existing proration units pursuant to the subject orders.

Public Procedures and Effective Date

A notice regarding Colorado's application was issued on February 21, 1980. (45 FR 13519, February 29, 1980). The comment period expired on March 7, 1980. No comments were received.

In view of the above discussion, the Commission approves the alternative filing requirements submitted by Colorado and deems satisfied the provisions of § 271.305 (b) and (c) and § 274.204(d)(4) as noted above. The Commission believes that good cause exists to make the alternative filing requirements effective immediately for all determinations which have not yet become final under § 275.202 as of the day before the date of issuance of this order.

(Natural Gas Act, as amended, 15 U.S.C. § 717-717w; Department of Energy Organization Act, 42 U.S.C. § 7107-7352 Exec. Order No. 12009, 42 FR 46267; Natural Gas Policy Act of 1978, 15 U.S.C. § 3301-3432)

In consideration of the foregoing, Part 274 of Subchapter H, Chapter I, Title 18 Code of Federal Regulations is amended as set forth below, effective immediately for all determinations which have not yet become final under § 275.202 as of the day before the date of issuance of this order.

By the Commission.

Kenneth F. Plumb,
Secretary.

¶ 30,163]

45 F. R. 36375 (May 30, 1980)

18 CFR Part 282

[Docket No. RM80-24; Order No. 85-A]

Permanent Rule Defining Small Existing Industrial Boiler Fuel Users Exempt From Incremental Pricing Surcharges

Issued: May 20, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: Order No. 85, which was issued in this docket on May 8, 1980 (45 FR 31980, May 15, 1980), adopted a final rule defining small existing industrial boiler fuel users permanently exempt from incremental pricing surcharges under section 206(a)(2) of the Natural Gas Policy Act of 1978. Order No. 85 also set forth deadlines and procedures for filing exemption affidavits to obtain a permanent exemption. The Federal Energy Regulatory Commission hereby amends its final regulations to extend by 60 days the deadlines established in Order No. 85 pertaining to exemption affidavits. The amended regulations provide that:

(1) an exemption on the basis of company records or previously-filed

exemption affidavits continues until *August 31, 1980;*

(2) natural gas suppliers shall mail or otherwise supply exemption affidavits to appropriate facilities not later than *July 20, 1980;*

(3) executed affidavits shall be filed on or before *August 31, 1980.*

EFFECTIVE DATE: Effective May 20, 1980.

FOR FURTHER INFORMATION CONTACT: Alice Fernandez, Office of Producer and Pipeline Regulator, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 (202) 357–9095, or Carol M. Lane, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 (202) 357–8114.

Permanent rule defining small existing industrial boiler fuel users exempt from incremental pricing under the Natural Gas Policy Act of 1978.

Order No. 85, which was issued in this docket on May 8, 1980 (45 FR 31980, May 15, 1980), adopted a final rule defining small existing industrial boiler fuel users permanently exempt from incremental pricing surcharges under section 206(a)(2) of the Natural Gas Policy Act of 1978. Order No. 85 also set forth deadlines and procedures for filing exemption affidavits to obtain a permanent exemption.

The Commission, upon its own motion, has determined that an undue administrative burden may be place upon natural gas suppliers and industrial end-users by the exemption affidavit portion of the order. Due to the immediacy of the filing deadlines, coupled with the large number of industrial end-users required to be served with affidavits, it may not be possible for all affected persons to meet the existing deadlines. It is therefore appropriate to extend the exemption affidavit deadlines established in Order No. 85 for a period of two months. Accordingly, Part 282 is amended to provide that:

(1) an exemption on the basis of company records or previously-filed exemption affidavits continues until *August 31, 1980;*

(2) natural gas suppliers shall mail or otherwise supply exemption affidavits to appropriate facilities not later than *July 20, 1980;*

(3) executed affidavits shall be filed on or before *August 31, 1980.*

The amendments adopted in this order relieve administrative burdens imposed on natural gas suppliers and industrial boiler fuel users; accordingly, the Commission finds there exists good cause to make them effective immediately.

(Natural Gas Policy Act of 1978, Pub. L. No. 95–621, 92 Stat. 3350, 15 U.S.C. 3301, *et seq.*)

In consideration of the foregoing, Part 282 of Subchapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,

[¶ 30,164]

45 F. R. 37420 (June 3, 1980); 45 F. R. 68389 (October 15, 1980)

18 CFR Part 141

[Docket No. RM80–61]

Statements and Reports (Schedules); Order Discontinuing Reporting Requirements

Issued: May 28, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) hereby discontinues FPC Form No. 12B (18 CFR 141.53), Form No. 12C (18 CFR 141.54), Form No. 12E–2 (18 CFR 141.56), and Form No. 12F (18 CFR 141.57), which require various reports and information on the generation of electricity. These forms are eliminated because the Commission no longer needs the data reported thereon to carry out its regulatory responsibilities.

EFFECTIVE DATES: May 28, 1980, for elimination of Form Nos. 12B, 12C and 12F; October 1, 1980, for elimination of Form No. 12E–2.

FOR FURTHER INFORMATION CONTACT:
Daniel G. Lewis, Federal Energy Regulatory Commission, Office of Electric Power Regulation, 825 N. Capitol Street, N.E., Mail Stop 300RB, Washington, D.C. 20426 (202) 376-9227.

SUPPLEMENTARY INFORMATION:

I. Background and Summary

The Federal Energy Regulatory Commission (Commission) by this rule eliminates from its regulations the following Federal Power Commission (FPC) forms: Form No. 12B, "Industrial Electric Generating Capacity (detailed information)" (18 CFR 141.53); Form No. 12C, "Industrial Electric Generating Capacity (limited information)" (18 CFR 141.54); Form No. 12E-2, "Supplemental Power Statement" (18 CFR 141.56); and Form No 12F, "Power Line Construction Data" (18 CFR 141.57).

Form No. 12B requires detailed information concerning electric generating equipment owned or operated by industrial establishments. This information is not currently being collected by this Commission or the Energy Information Administration (EIA).

Form No. 12C requires information concerning the net generation of electric energy and the installed nameplate capacity of industrial plants. Information required by this form is currently being collected by EIA.

Form No. 12E-2 requires information on monthly energy, capability and peak load data, near-term summer/winter capability and peak load data, long-term plans with respect to generating units and transmission lines, and long-term forecasts on energy and peak load. Information required by this form is currently being collected by EIA.

Form No. 12F requires information concerning power lines and generating plants. Information required by this form is currently being collected by the EIA.

The forms were devised by the Federal Power Commission (FPC) (the Commission's predecessor agency) pursuant to the authority granted in sections 301, 309 and 311 of the Federal Power Act.[1] The authority under section 311 was transferred to the Secretary of Energy pursuant to section 301(b) of the Department of Energy Organization Act [2] (42 U.S.C. 7101, *et seq.*). The Secretary in turn delegated this authority to the Economic Regulatory Administration (ERA) (Department of Energy Delegation Order No. 0204-4 (10 CFR 1001.1)), and to the Commission to the extent necessary to perform its other functions (Delegation Order No. 0204-1, 42 FR 55637 (October 18, 1977)). The Commission has determined, however, that the data required by Form Nos. 12 B, 12C, 12E-2 and 12F are not central enough to its functions to justify continued collection of the data by this Commission. In view of this, the Commission is hereby eliminating from its regulations those sections which provide for the Commission's collection of the information pursuant to those forms.

II. Effective Date

The ERA, which is responsible for utilizing the information from Form Nos. 12B, 12C, 12E-2 and 12F, has determined that the collection of data from Form No. 12E-2 is necessary to the performance of its statutory responsibilities. The Commission will, therefore, delay until October 1, 1980, the effective date for elimination of Form No. 12E-2 so that ERA may have sufficient time to obtain approval from the Office of Management and Budget for the future collection of these data.

The elimination of the other forms, Form Nos. 12B, 12C and 12F simply amends the Commission's regulations to reflect that the Commission no longer requires the information gathered from these forms. For this reason, the requirement to report information pursuant to these forms will be eliminated May 28, 1980.

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[1] Form Nos. 12B and 12F were established under FPC Order No. 141 (Form No. 12F was amended by Order Nos. 372 and 527); Form 12C was established by Order No. 559; and Form No. 12E-2 was established by Order No. 544.

[2] Section 301(b) provides that powers vested in the FPC under the FPA and the natural Gas Act (NGA) (15 U.S.C. 717) which were not transferred to the Commission by Title IV of the DOE Act are vested in the Secretary.

The Commission accordingly finds that notice and public procedure are unnecessary pursuant to 5 U.S.C. § 553(b), and that there is good cause under 5 U.S.C. § 553(d) to make the amendments in this rulemaking effective as provided.

(Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.;* Federal Power Act, as amended, 16 U.S.C. 792, *et seq.;* Department of Energy Delegation Order 0204-1, 42 FR 55637 (October 18, 1977); Department of Energy Delegation Order 0204-4 (10 CFR 1001.1))

For the foregoing reasons, Title 18 of the Code of Regulations is amended in Part 141 as provided below, effective as set forth above.

By the Commission.

Lois D. Cashell,
Acting Secretary.

[¶ 30,165]

45 F. R. 38354 (June 9, 1980)

Note: The effective date of Order No. 89 has been changed to December 31, 1980. See ¶ 30,197.

18 CFR Part 141

[Docket No. RM80-63; Order No. 89]

Electric Utilities; Order Discontinuing Reporting Requirement

June 2, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) hereby discontinues reporting requirement RO211, "Report of impending emergencies, load reductions, and/or service interruptions in bulk electric power supply and related power supply facilities" (18 CFR 141.58), because the information collected by means of the reporting requirement is no longer needed by the Commission to carry out its regulatory responsibilities.

EFFECTIVE DATE: September 1, 1980.

FOR FURTHER INFORMATION CONTACT: Daniel G. Lewis, Federal Energy Regulatory Commission, Office of Electric Power Regulation, 825 North Capital Street, NE., Mail Stop 300 RB, Washington, D.C. 20426 (202) 376-9227.

I. Background and Summary

The Federal Energy Regulatory Commission (Commission) by this rule eliminates from its regulations "Form RO211"[1], a reporting requirement set forth in 18 CFR 141.58, because the Commission no longer needs the data collected therein to carry out its regulatory responsibilities. That section of the Commission's regulations required electric utilities, licensees or other entities engaged in the generation or transmission of electric energy to report impending emergencies, load reduction, and/or service interruptions in bulk electric supply and related power supply facilities.

Form RO211 was established by Federal Power Commission (FPC)[2] Order No. 331 (issued December 20, 1966), and was amended by FPC Order No. 331-1 (issued May 21, 1970) under authority granted the FPC by sections 202(c)[3] and 311[4] of the Federal Power Act (FPA) (16 U.S.C. 824a(c) and 825j).

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[1] The reporting requirement set forth in 18 CFR 141.58 was not given an official designation by the Commission. "Form RO211" is the clearance number assigned to the reporting requirement by the Office of Management and Budget (OMB). For purposes of convenience the term "Form RO211" will be used to describe the reporting requirement in 18 CFR 141.58.

[2] The Commission's predecessor agency.

[3] Section 202(c) authorizes the temporary connection of facilities, during times of war or national emergency, for the generation of electric energy.

[4] Section 311 authorizes investigations and information gathering relating to electric energy.

The Commission's authority under those sections was transferred to the Secretary of Energy (Secretary) by section 301(b) of the Department of Energy Organization Act (DOE Act) 42 U.S.C. 7151, *et seq.*).[5] The Secretary in turn delegated the authority to administer sections 202(c) and 311 to the Economic Regulatory Administration (ERA).[6] The authority to administer section 311 was also delegated to the Commission to the extent needed to perform its other vested or delegated functions.[7]

As a result of these changes in the Commission's regulatory responsibilities, the Commission has determined that the data required by Form RO211 is not sufficiently central to its functions to justify continued collection of the data by this Commission. In view of this, the Commission is eliminating from its regulations that section which provides for the Commission's collection of the information pursuant to Form RO211.[8]

The ERA, however, has determined that collection of the data contained in this form is necessary in order to discharge its statutory responsibilities.[9] To allow ERA sufficient time to complete its own rulemaking proceedings and receive OMB approval for collection of the information, the Commission will comply with ERA's request to continue Form RO211 until September 1, 1980. Accordingly, the effective date for the discontinuance of Form RO211 and the revocation of § 141.58 of the Commission's regulations is September 1, 1980.

II. Public Procedure and Effective Date

The elimination of Form RO211 is simply a ministerial act, whereby the Commission's regulations will be made to reflect the Commission's actual practice. For this reason, the Commission finds that notice and public procedure are unnecessary pursuant to 5 U.S.C. 553(b).

In order to allow ERA sufficient time to implement regulations which would include the reporting requirement RO211, elimination of the form and the corresponding amendment to the Commission's regulations will become effective on September 1, 1980.

(Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.*; E. O. 12009, 3 CFR 142 (1978))

For the foregoing reasons, Chapter I of Title 18, Code of Federal Regulations, is amended in Part 141, effective September 1, 1980, as set forth below.

By the Commission.

Kenneth F. Plumb,
Secretary.

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[5] Section 301(b) vests in the Secretary the powers of the FPC under the FPA and the Natural Gas Act (NGA) (15 U.S.C. 717, *et seq.*) which were not transferred to the Commission by Title IV of the DOE Act.

[6] Department of Energy Delegation Order No. 0204–4 (10 CFR 1001.1).

[7] Delegation Order No. 0204–1, October 1, 1977 (42 FR 55637, October 18, 1977).

[8] Section 206 of the Public Utility Regulatory Policies Act (PURPA) (16 U.S.C. 824a) provides, among other things, that the Commission shall require each public utility to report any anticipated shortage of electric energy or capacity that would affect the utility's capability of serving its wholesale customers. Although that section might appear to require information similar to that contained in Form RO211, the issues relating to section 206 and the Commission's determination on what data are required under that section are being considered by the Commission in a separate docket. See *Notice of Inquiry*, Docket No. RM79–52, issued April 22, 1980 (45 FR 28162, April 28, 1980). See also Interim Regulations (18 CFR Part 294).

[9] ERA has issued a Notice of Proposed Rulemaking which would effect this transfer of authority to receive these reports of incidents on the electric power system (45 FR 20109, March 27, 1980).

[¶ 30,166]

45 F. R. 39497 (June 11, 1980)

18 CFR Part 281

[Docket No. RM79–15]

Amendment to the Regulation for the Implementation of Section 401 of the Natural Gas Policy Act

Issued: June 3, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Interim rule.

SUMMARY: The Federal Energy Regulatory Commission is amending 18 CFR Part 281, the agricultural curtailment rule, to establish new filing dates for interstate pipelines to serve a draft index of entitlements on their customers and for customers to file protests to such drafts. The new filing dates are those which were applicable in 1979: September 14 and September 21. If the Commission had not amended the rule, pipelines would have had to serve these documents before they received necessary information from essential agricultural users. The amendment allows pipelines to serve these documents after they have received all information necessary to prepare the document.

EFFECTIVE DATE: June 3, 1980.

DATES: Written comments by July 3, 1980. Request to participate in hearing by June 20, 1980. Hearing date: June 30, 1980.

ADDRESS: Written comments and request to participate to: Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (Reference Docket No. RM79–15).

HEARING LOCATION: Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Robert F. Christin, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8432.

Before Commissioners: Georgiana Sheldon, Matthew Holden, Jr., and George R. Hall.

In the matter of amendment to the regulation for the implementation of Section 401 of the Natural Gas Policy Act.

I. Background

In order No. 29, which was issued on May 2, 1979 (44 FR 26855, May 8, 1979) in this proceeding, the Commission established a final rule to ensure that natural gas for essential agricultural uses will not be curtailed unless curtailment is needed to protect certain enumerated high priority users, as provided in Section 401 of the Natural Gas Policy Act (NGPA).[1] Section 281.212(d) of the rule promulgated in Order No. 29 provides that for years subsequent to 1979, an interstate pipeline is required to serve draft tariff sheets and a draft index of entitlements on all customers and the Data Verification Committee by August 1. Section 281.213(c) of the rule provides that for years subsequent to 1979, written protests concerning the index of entitlements shall be filed no later than 30 days after a draft index of entitlements is served.

II. Discussion

Contemporaneously with this rule, the Commission is issuing, in Docket No. RM79–40, a notice of proposed rulemaking. The proposal would establish a final rule for the determination of alternative fuels for essential agricultural users pursuant to Section 401(b) of the NGPA.[2] Section 281.305 of the proposed rule would require an essential agricultural user to reduce its essential agricultural requirements to reflect the exclusion of volumes for which it has alternative fuel.

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[1] Order 29 was amended in Order Nos. 29–A, June 15, 1979 (44 FR 37499, June 27, 1979), 29–B, July 20, 1979 (44 FR 45922, August 6, 1979) and 29–C, October 22, 1979 (44 FR 61336, October 25, 1979).

Comments on the rule proposed in Docket No. RM79-40 are due on July 3, 1980. Because of the time required for consideration of the comments and promulgation of a final rule, the Commission believes that a final rule may not be promulgated in Docket No. RM79-40 before the pipelines have completed the work necessary to meet the filing deadline contained in Section 281.212(d). Therefore, to avoid uncertainty and unnecessary duplication of effort by the pipelines, the Commission is issuing a rule, effective immediately, to provide that under Subpart B of Part 281, the filing and service dates for 1980 shall be the same as for 1979.

III. Effective Date

The Commission hereby adopts and makes effective this interim rule without prior notice and opportunity of comment and without publication thirty days before its effective date. The interim rule amending the 1980 filing dates previously established in this proceeding is procedural in nature. Section 553 of the Administrative Procedure Act (5 U.S.C. § 553) does not require prior notice and opportunity to comment or publication thirty days before the effective date for procedural rules.

IV. Comment Procedures

A. *Written Comments.* Interested persons are invited to submit written comments, data, views, or arguments with respect to this interim rule. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should reference Docket No. RM79-15. An original and 14 copies should be filed. All comments received prior to 4:30 p.m. EDT, July 3, 1980, will be considered by the Commission prior to promulgation of a final regulation. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection in the Commission's Office of Congressional and Public Affairs, Division of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours.

B. *Public Hearing.* A public hearing concerning this interim rule and the proposal set forth in the Notice of Proposed Rulemaking in Docket No. RM79-40 on June 3, 1980, will be held in Washington, D.C. on June 30, 1980, beginning at 10:00 a.m. at the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. The exact location will be posted at the Commission on the morning of the hearing.

Requests to participate should be directed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, no later than June 20, 1980. Requests should reference Docket No. RM79-15 and should indicate the amount of time required for the oral presentation, and the telephone number at which the person making the presentation can be reached. Persons participating in the public hearing should, if possible, bring 50 copies of their testimony to the hearing. A list of participants in the hearing will be available at the hearing on the morning it is convened.

Members of the hearing panel will be designated by the Chairman of the Commission. The hearing will not be of a judicial or evidentiary type. There will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested person may submit questions to the presiding officer to be asked of persons making statements. The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. Any further procedural rules will be announced by the presiding officer at the hearing. Transcripts of the hearing will be available through the Commission's Division of Public Information, Office of Congressional and Public Affairs.

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[2] An interim rule was issued in Order No. 55 Docket No. RM79-15, October 26, 1979 (44 FR 62484, October 31, 1979).

(Natural Gas Act amended, 15 U.S.C. §§ 717–717w: Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301–3432; Department of Energy Organization Act, 42 U.S.C. §§ 7101–7352; E.O. 12009, 3 CFR 142 (1978))

In consideration of the foregoing, Part 281, Chapter I of Title 18, Code of Federal Regulations is amended to read as set forth below.

By the Commission.
Kenneth F. Plumb,
Secretary.

[¶ 30,167]

45 F. R. 37812 (June 5, 1980)

18 CFR Part 260

[Docket No. RM80-20; Order No. 88]

Order Revising Report of Gas Supply and Requirements

May 30, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) revises Form No. 16, "Report of Gas Supply and Requirements" (18 CFR 260.12). The revisions reduce the number of schedules contained in the form, and change the format of the schedules and the instructions which accompany them. The changes in Form No. 16 reflect the results of an ongoing validation program to reduce reporting burdens placed on companies subject to Commission jurisdiction.

EFFECTIVE DATE: June 30, 1980.

FOR FURTHER INFORMATION CONTACT:
Robert Schroeder, Office of Pipeline and Producer Regulation, Curtailment Branch, Room 7300-B, Federal Energy Regulatory Commission, 825 N. Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8828.

Revision of FERC Form No. 16, Report of Gas Supply and Requirements

A. Background

Form No. 16 "Report of Gas Supply and Requirements" is submitted on a semiannual basis by natural gas companies making sales in interstate commerce pursuant to an order of the Federal Energy Regulatory Commission (Commission).[1] The form shows system-wide summary information of a pipeline's gas supplies, requirements and curtailments. The Commission uses the information from Form No. 16 to provide for emergency sales and certificates and to review curtailment plans and revisions.

On January 18, 1980, the Commission issued a Notice of Proposed Rulemaking to revise Form No. 16, "Report of Gas Supply and Requirements" 45 FR 5309 (January 23, 1980). This rulemaking amends the content, format and instructions of Form No. 16. It is part of the Commission's ongoing validation program, the purpose of which is to eliminate unnecessary reporting burdens on the industries regulated by the Commission. The rulemaking also revises the Form No. 16 definitions and data requests to conform to recent regulations which implement the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3301–3422).

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[1] Form No. 16 was initially promulgated in Order 489, Docket No. R-472, 38 Fed Reg. 23516 (August 31, 1973), 50 FPC 561 (1973). It was revised in Order 523, Docket No. R-472, —*Fed. Reg.* —(———, 1975), 53 FPC 352 (1975).

By that Notice, the Commission proposed to reduce the number of schedules which must be filed from ten to eight by revising the schedules and renumbering them so that Schedules 1 through 4 would depict 12 months of actual experience and Schedules 5 through 8 would depict corresponding data for 12 months of projected or anticipated data. Thus, the proposed list of new Schedules was as follows: Schedule No. 1 [2] (Summary of Actual Supply, Requirements and Net Deficiency or Surplus); Schedule No. 2 (Actual Sources of Supply Adjusted for Losses); Schedule No. 3 (Actual Storage Operations); Schedule No. 4 (Actual Deliveries, Requirements and Net Deficiency or Surplus by Customer); Schedule No. 5 (Summary of Projected Supply, Requirements and Net Deficiency or Surplus); Schedule No. 6 (Projected Sources of Supply Adjusted for Losses); Schedule No. 7 (Projected Storage Operations); Schedule 8 (Projected Deliveries, Requirements and Net Deficiency or Surplus by Customer).[3]

The Commission also proposed to consolidate, clarify and expand the instructions of Form No. 16 to provide respondents with better guidelines on general filing requirements, definitions, and line items on a schedule-by-schedule basis. Some important changes in the proposed instructions included: replacing the term "curtailment" with the phrase "net deficiency or surplus" of the pipeline (this would be the difference between "net available for market" [4] from the pipeline and "pipeline requirements"); the elimination of the requirement to report monthly volumes on an average daily basis; and the use of more subtotals to overcome past problems users have had with inconsistencies within and among schedules.

Finally, format changes were proposed to each respondent preparation and to facilitate both public and regulatory uses of the data. These changes included reserving certain columns of each schedule for the reporting of monthly volumes; assigning unique schedule numbers to overcome the present ambiguity of using the same schedule number for both actual and projected data; and reordering the schedules so that there would be a progression from highly aggregated data to supporting detail.

The Commission also proposed to amend those regulations which reference Form No. 16. Section 260.12(a) would be amended to designate Form No. 16 as "FERC Form No. 16." Section 260.12(b) would be revised to reflect the necessity of filing an original and six copies with the EIA. A new section 260.12(c) would be added to provide for waiver of filing for those companies which show that there is good reason for them not to file the form. This provision conforms to past Commission practice respecting the filing of Form No. 16.

B. Summary of Comments and Changes to Form No. 16

In response to the proposed rulemaking, the Commission received ten comments.[5] Of these, nine were natural gas pipelines which are required to file the form [6] and one was an industry association. The general reaction to the rulemaking was favorable. A number of changes were suggested by commenters, many of which have been incorporated into Form No. 16, as discussed below.

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[2] The Schedules of Form No. 16 are identified by Roman numerals on the actual form. They are identified by Arabic numerals in this rulemaking.

[3] Form No. 16 is comprised of eight actual schedules. A ninth schedule was added in response to comments requesting additional space for footnotes to their responses.

[4] "Net available for market" has been changed to "net available for sale" pursuant to a request in the comments. *See* discussion at B(2)(a), *infra.*

[5] Arkansas Louisiana Gas Company, Columbia Gas Transmission Corporation, EL Paso Natural Gas Company, Natural Gas Pipeline Company of America, Tennessee Gas Pipeline Company, Texas Gas Transmission Corporation, Transcontinental Gas Pipe Line Corporation, Northern Natural Gas Company, Southern Natural Gas Company, and Interstate Natural Gas Association.

[6] A total of 52 natural gas pipelines are now required to file FERC Form No. 16.

1. *General Comments.* In addition to their remarks on the specific schedules of Form No. 16, the commenters to the proposed rulemaking filed remarks in three general areas: (1) the timing of implementation of the revised Form No. 16 and subsequent filing dates; (2) the burden imposed by certain revisions to the form; and (3) technical changes.

a. *Filing Dates.* The Commission has designated September 30, 1980 as the filing date for the initial submittal of the revised Form No. 16.[7] The general instructions provide, as they did in the original Form No. 16, that subsequent filings will be due on April 30 and September 30 of each year so that the information in the form can be used by the Commission in planning for the heating season.

Pipelines which purchase gas from other pipelines argued that it is extremely difficult to get the information necessary to complete the form by the April 30 and September 30 deadlines, and that an additional 15 days is needed to report this data. Under these circumstances, the pipelines may apply for an extension in their filing period as provided in the Commission's regulations at 18 CFR 1.13.

b. *Burden.* Only two commenters claimed that the proposed form created a net additional reporting burden by the inclusion of new data requirements. The main objection related to the transportation of self-help gas and is addressed in detail later in this section.

One other complaint was that the schedule-by-schedule instruction in Form No. 16 for peak day information represented an unnecessary increase in the reporting burden. Several pipelines also stated that the proposed Form No. 16 required the same peak day information that is elicited in Form No. 2.[8]

The Commission believes that the peak day data supplied in Form No. 2 are less specific than those of Form No. 16; however, to reduce the respondent reporting burden while securing the most important data, all peak day information proposed for the new Form No. 16 as well as peak day data in the original Form No. 16 has been eliminated.

One comment claimed that Form No. 16 duplicates the information required in EIA Form No. 50, "Alternate Fuel Demand Due to Natural Gas Curtailment." While the Commission finds that a few items of information requested in Form No. 16 are similar to those of Form No. 50; Form No. 50 requires information from distributors which are based on gas supplies from the distributor's sources, including all different pipelines. Form No. 16 only gathers information from individual pipelines. Since it is difficult or impossible to segregate many of the data elements of the various pipelines included in Form No. 50, Form No. 16 will continue to be used to gather this information.

Several comments asserted that the additional data requests of lines 13, 14, and 15 of Schedules 1 and 5 concerning self-help gas transported to the respondents' customers[9] are too burdensome. Information is requested for certain exempted purchases, direct assignments or other purchases by the respondent pipeline's customers which are transported by that pipeline. Some respondent pipelines claimed that the requested information is difficult to obtain from their customers and that the Commission is in a better position to secure that information from customers.

The Commission finds that these exempted purchases and transportations of gas must be monitored in the context of overall supplies of the customers of a pipeline system. Form No. 16 is the only available form which provides monthly data on such transactions as compared to other pipeline supplies to their customers. The pipelines are in the best position to report this information from the customers since they have to record total deliveries to their customers. Because the Commission regulates the pipelines and not their customers, the Commission should look to the pipelines for the required information. Furthermore, this method of collecting customer information has been used successfully since 1973 by pipelines for Form No. 16 collections and is the most efficient way to link such transactions to particular pipelines. Of course, if no self-help information is available, no entry of such data can be made.

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[7] Several commenters indicated that they could not file the new Form No. 16 by the proposed filing date of April 30, 1980. Therefore, the date was changed from April 30, 1980 to September 30, 1980. *See* "Notice of Change in Proposed Implementation Date," Docket No. RM80-20 (Mar. 20, 1980), 45 *Fed. Reg.* 19565 (Mar. 25, 1980).

[8] Form No. 2 is the "Annual Report for Natural Gas Companies (Class A and Class B)", 18 CFR 260.1.

[9] The purpose of the requirement is to determine the extent to which a pipeline's customers are able to acquire supplemental gas supplies.

It was suggested that transportations for customers reported on lines 13, 14, and 15 which are less than 10 MMcf per month should be aggregated to reduce the reporting burden. The Commission has deleted the requirment to report individual transaction volumes to ease the burden and has done so for all transactions. It only requires that the buyer and seller of each transaction be identified.

c. *Technical Changes.* Some commenters stated that they would prefer to use a dekatherm basis instead of Mcf to reply to Form No. 16. The general instructions provide that dekatherms may be used if the pipeline supplies with the form a factor based on average heat content so that conversion may be made to Mcf.

Some commenters asserted that Form No. 16 provided insufficient space for reporting certain classes of data. A provision has been included whereby details may be filed in support of the summary data as attachments to Schedules 1 through 8. For the convenience of certain respondents, the Commission has included an instruction which permits pipelines to use a computerized format which follows the format of Form No. 16. However, total and subtotal line numbers should be identical to the original form.

Some commenters noted that the form required the reporting of company code numbers, without specifying the standard for which the codes would be used by respondents. The Commission has, therefore, amended the general instructions to provide that the pipelines use the publication, *Buyer/Seller Codes,* where possible.

Since some of the gas transported for customers is not actually delivered to them because the gas is lost or used as a compressor fuel by the pipeline, an instruction has been added to require that the respondent pipelines shall report only those transportation volumes actually delivered to the customers.

2. *Changes to Particular Schedules.*—a. *Schedules 1 and 5.* Several comments pointed out that more than one case docket may be associated with anticipated new gas suppplies reported on Schedules 1 and 5. The words "docket number" on Attachment I have, therfore, been changed to "docket numbers".

The Commission also adopted the suggestion that pipelines which discuss anticipated new supplies may use footnotes that indicate all regulatory approvals necessary to attach new gas sources.[10]

Another suggestion that has been adopted by the Commission was to change the line 10 ("Net Available for Sale") provision of the subtotals of "line 04 less line 09", to "line 04 plus line 09" since the line 09 figure may be either positive or negative.

One comment requested that a section be added to report adjustments such as hurricanes, pipeline breaks and cutbacks. Line 05 "(Loss of Supply") should be used to report such adjustments.

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[10] The Commission had inadvertently omitted parentheses on lines 05 and 06 on which volumes that consistently reduce supply are reported. These have been added to the form.

customers of the pipeline to bear the particular cost.[96]

When a pipeline files its case-in-chief in a rate proceeding the information it files may be considered by the Commission and participants in determining whether the costs described in that filing are of the kind described in the policy statement. If they are, those costs should not be subject to challenge (except with respect to the level of the claimed cost).

Finally, section 2.102(c) sets out the definitions necessary to relate the policy statement to the NGPA and the regulations of Subpart K. The term "production-related costs" is given the same meaning for purposes of the policy statement as it has under Subpart A of Part 270. The terms "first sale" and "interstate pipeline" are given the same meanings as those terms have under the NGPA. The reference in the policy statement to "prudent compression costs" is, as already described, defined in terms of the types of compression that will be considered prudent.[97]

E. Effective Dates and Further Proceedings.

The interim regulations of Subpart K of Part 271 and Subpart A of Part 270, are amended as set forth below and are being made effective immediately in order to properly implement the NGPA. Good cause to do so exists because most of the changes made to the interim regulations either remove restrictions or clarify the existing regulations. With respect to amendments that suspend the application procedure of § 271.1104 for gathering and compression allowances, these amendments are being made effective immediately because such applications would not be acted upon during the pendency of generic proceedings to determine the appropriate level for these allowances. To permit further application would serve no purpose or administrative practicality. In that these allowances will, for potential applicants, be considered retroactively to the date of this suspension, and in that application may still be made under the provisions of section 502(c) of the NGPA for these allowances, potential applicants should not be adversely affected by the suspension.

Because it is a policy statement, and necessary for the proper implementation of the NGPA and the NGA, the amendment to Part 2 of the Commission's regulations is made effective immediately.

Because the amendments to Parts 270 and 271 made by this Rule are interim, comments will be considered before they are made final. Interested persons may submit comments on the amendments made under this Rule and the policy statement by submitting written data, views or arguments to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, on or before September 22, 1980. Each person submitting a comment should include his name and address, identify Docket No. RM80-47, and give reasons for any recommendations. An original and 14 conformed copies should be filed with the Secretary of the Commission. Comments should indicate the name, title, mailing address, and telephone number of one person to whom communications concerning the amendments may be addressed. Written comments will be placed in the Commission's public files and will be available for public inspection at the Commission's Office of Public

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[96] In a later Notice of Proposed Rulemaking we will propose amendments to the filing requirements of § 154.93 which specify what information will be required under the policy. In the interim, pipelines should be on notice that the Commission will exercise its authority to require the filing of additional evidence as warranted.

[97] *See* the attached Appendix for a discussion of various examples of compression in the context of the definition of "prudent compression cost". The Appendix—"Examples of Various Compression Activities" is filed with the Office of the Federal Register as part of the original document. Copies may be secured by writing to the Federal Energy Regulatory Commission, Office of Public Information, Washington, D.C. 20426.

best copy available

Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours.

The Commission intends to hold a public hearing on the amendments made to Subpart A of Part 270 and Subpart K of Part 271, as required by section 502 of the NGPA. The date and location of such hearing will be announced in the future. The amendments shall not become final until the Commission has had an opportunity to receive oral presentation of relevant data, views and arguments.

(Natural Gas Act, as amended, 15 U.S.C. § 717, *et seq.;* Department of Energy Organization Act, 47 U.S.C. §§ 7101–7352; E.O. 12009, 42 F.R. 46267; Natural Gas Policy Act of 1978; 15 U.S.C. §§ 3301–3432)

In consideration of the foregoing, Parts 2, 270 and 271 of Title 18, Code of Federal Regulations, are amended as set forth below; to become effective on the date the Rule is issued. (July 25, 1980)

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,179]

45 F. R. 53116 (August 11, 1980)

18 CFR Part 277

[Docket No. RM80-8; Order No. 95]

Bona Fide Offers; Right of First Refusal

Issued July 28, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: This order implements sections 315(b) and (c) of the Natural Gas Policy Act of 1978 (NGPA). Section 315(b) establishes that the purchaser of natural gas which is removed from Natural Gas Act jurisdiction under section 601(a)(1)(B) of the NGPA has the right to a bona fide offer to purchase such natural gas and the right of first refusal which permits the purchaser to buy such natural gas under the terms of an offer made by a third party purchaser. The order establishes procedures by which the requirements of bona fide offer and the right of first refusal shall be satisfied. Under the authority granted in section 315(c), the Commission has prescribed recordkeeping requirements pertaining to sales occurring under section 315(b).

EFFECTIVE DATE: September 1, 1980.

FOR FURTHER INFORMATION CONTACT: Leslie J. Lawner, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol St., N.E, Washington, D.C. 20426, (202) 357–8027.

Before Commissioners: Charles B. Curtis, Chairman; Georgiana Sheldon, and George R. Hall.

I. Background

On November 14, 1979, the Federal Energy Regulatory Commission (Commission) issued a Notice of Proposed Rulemaking in Docket No. RM80–8, (44 FR 66208, November 19, 1979). The proposed rule would implement section 315(b) of the Natural Gas Policy Act of 1978 (NGPA), 15 U.S.C. § 3375(b), concerning bona fide offers and the right of first refusal. Section 315(b) imposes a duty on the seller of certain categories of natural gas to make a bona fide offer for the continued sale of such gas upon the expiration of the contract for sale covering such gas. If the bona fide offer is rejected, and the seller attempts to sell the gas to a person other than the original purchaser, section 315(b)(3) grants a right of first refusal to the original purchaser of such natural gas, which right permits the original purchaser to match the terms of a third party offer to purchase the natural gas.

In summary, the notice proposed to impose requirements involving bona fide offers and the right of first refusal on certain sales of gas which gas (1) was committed or dedicated to interstate commerce on November 8, 1978, and (2) has been determined to be high-cost gas described in section 107(c)(1) through (4) of the NGPA, new natural gas under section 102(c), or gas produced from a new onshore production well under section 103. The proposed provisions involving bona fide offers required that a bona fide offer to sell the gas to the original purchaser be made, in those cases where the original contract had not yet expired, 20 days prior to expiration of the contract. The original purchaser was given 20 days to accept the offer in writing. If the offer was rejected, the seller could sell the gas to other purchasers only if the original purchaser rejected his right of first refusal, that is, refused to purchase the gas under terms substantially accepted in principle by a third party in an arms-length transaction. The third party could not be an affiliate of the seller. If the purchaser accepted such an offer, he had the right to change the delivery point and physical conditions of delivery specified in the offer to those found in the subject contract.

A seller of gas subject to these provisions was free to sell the gas to third person only if (1) the bona fide offer was rejected, (2) the offer submitted pursuant to the right of first refusal was rejected, and (3) the gas was, or is, sold under the terms of the offer subject to the right of first refusal, which the original purchaser rejected. Other provisions required that the gas must continue to be sold to the original purchaser, where the contract expired, until the bona fide offer requirements were met. Relief was extended to original purchasers as the Commission determined to be appropriate, for sales which took place prior to the promulgation of this rule. The proposal also required the retention of certain records.

Interested persons were invited to submit written comments on the proposed rule on or before December 19, 1979. A public hearing concerning the proposed rule was scheduled to be held on December 14, 1979. The hearing was cancelled due to lack of interest in participation by the public. All written comments received in this docket are in the Commission's public files and are available for public inspection in the Commission's Division of Public Information.

II. Summary of Comments

Written comments concerning the proposed rule were submitted by interested persons and were reviewed by the Commission. The comments which were received raised numerous issues which will be discussed in turn.

A. Bona Fide Offers

1. *Form of Bona Fide Offers.*—Section 277.203(b) of the proposed rule defined the term "bona fide offer" as:

> A written offer by the seller to the original purchaser which would be legal for such purchaser to accept under the Natural Gas Act and which is sufficiently firm that if accepted by the original purchaser would result in a binding contract enforceable by the seller and the purchaser.

Numerous persons commented that the requirement that such offer must be legal for the purchaser to accept under the Natural Gas Act (NGA) (15 U.S.C. §§ 717–717w) was not clear. One commenter indicated that what was probably intended by this requirement, as it appeared in the Conference Report of the NGPA, was compliance with the legal requirements pursuant to the regulation of interstate pipelines under the transportation sections of the NGA.

Under the Natural Gas Act, the Commission has ruled that various types of contractual clauses are impermissible. For example, certain types of indefinite rate escalation provisions were prohibited by the Commissions in Order No. 174–B, 13 F.P.C. 1576, Order No. 232, 25 F.P.C. 379, and Order No. 242, 27 F.P.C. 339. Permissible contractual clauses concerning pricing provisions are set forth in § 154.93 of the Commission's regulations. "Most favored nation" clauses have similarly been abrogated by the Commission (See, § 154.93 of the Commission's regulations and Order No. 174–B, 13 F.P.C. 1576). The Commission contemplated legal strictures of this nature when defining the term "bona fide offer" and views such strictures as intended by the Conferees when they stated that the offer should include terms which are legal to accept under the Natural Gas Act (Joint Explanatory Statement of the Committee on Conference Natural Gas Policy Act of 1978, P.L. 95-621, H. Report No. 95-1126, August 16, 1978, at page 111).

Other comments were made concerning the form of the bona fide offer and the degree of specificity of the offer required by the proposed rule. Several commenters noted that it is the common practice to have the purchaser submit the proposed contract to the producer. Both the proposed rule and § 277.205 of the final rule would require that the producer submit the offer to the purchaser. Because the rule does not reflect business practice, the commenters suggested that the producer need not be required to submit an actual and detailed contract to the purchaser. Rather, it was suggested the producer could simply be required to make an offer or specify terms which will enable the parties to reach an agreement in principle without compelling the producer to draft a legally sufficient and binding contract.

The Commission is not convinced that the proposed regulations should be changed in this regard. The regulations do not require that the seller submit an "actual and detailed contract" to the seller. They merely require that the offer be "sufficiently firm that, if accepted by the original purchaser, [it will] result in a binding contract enforceable by the seller and the purchaser." (*See*, § 277.203(c)). Thus, all that needs be submitted to comply with the bona fide offer requirement is an offer which, if accepted, is legally sufficient to bind the parties. Detailed contractual provisions can be added at a later stage in the negotiation if desired by the parties.

2. *Definitions.*—In § 277.203(J) of the proposed rule, the term "original purchaser" was defined to include any successor in interest to such original purchaser. One commenter suggested that a definition of "seller" should also be included in the rule, and that it should be defined to include successors to sellers who are subject to the section 315(b) obligations. The Commission believes that such a definition would carry out the purposes of section 315(b) by ensuring that no purchaser of natural gas eligible for the protection afforded by section 315(b) is denied its rights because of a change in the identity of the seller of such natural gas. Accordingly, the term "seller" will be defined in the regulation to include successors to sellers for the purposes of this rule.

3. *Scope of Bona Fide Offer.*—A general rule is established in § 277.205(a) governing bona fide offers. The proposal provided that deliveries of gas under a subject contract may not be discontinued until a bona fide offer has been rejected by the original purchaser. Two commenters felt that this section should be clarified to state that sales may not be discontinued before the contract expires. The general rule has been amended to clarify the fact that it is the Commission's intent that sales not be discontinued prematurely.

With respect to the scope of the bona fide offer rule, one commenter stated that the offer is statutorily required under section 315(b) of the NGPA only where the contract expired before December 1, 1978. Pursuant to this interpretation, natural gas which was sold under a contract which had not expired as of November 8, 1978, would be subject only to the right of first refusal. To support this interpretation, the commenter cites the use of the word "or" in section 315(b)(3) (which provides when the right of first refusal arises), as indicating that *either* the contract has expired, presumably after November 9, 1978, *or* the bona fide offer has been rejected. The pertinent language in section 315(b)(3) reads:

> The Commission shall require that following—(A) the expiration or termination of any contract . . ., *or* (B) any rejection of any bona fide offer . . ., such person who would have been entitled to receive such natural gas shall be granted a right of first refusal . . . . (emphasis added).

This position is untenable for several reasons. First, nothing in section 315(b)(3)(A) indicates that the reference to "expiration or termination of any contract" was limited to those contracts which expire after November 9, 1978. Second, in section 315(b)(2), which provides for the bona fide offer, no distinction is made between natural gas sold under a subject contract which expired prior to the enactment of the NGPA, and natural gas sold under a subject contract which expired after the enactment of the NGPA. The language of section 315(b)(2) provides that if natural gas which was committed or dedicated to interstate commerce on the day before the date of enactment of the NGPA, has been removed from Natural Gas Act jurisdiction, and was produced on or after December 1, 1978, a bona fide offer must be made to the original purchaser to continue to sell the gas after termination of the contract. The language of section 315(b)(2) regarding its applicability is clear on its face.

Other factors also point against this commenter's reading of the statute. The Commission interprets the use of the word "or," emphasized by the commenter, to indicate that the right of first refusal vests in all cases at the earlier of the expiration of the contract or the rejection of the bona fide offer. The two clauses, when read together, ensure that the original purchaser is not denied the protection of section 315 where the contract expires before the requirements of the bona fide offer provision have been met.

The Commission's view is supported by the Conference Report, *supra*, which states that:

> Following the expiration of any contract covering such natural gas, *and* any rejection of a bona fide offer by the purchaser who would have been entitled to receive the gas under the Natrual Gas Act, such purchaser is granted a right of first refusal . . . (p. 111) [emphasis added]

Here, the use of "and" clearly implies that Congress intended to have a bona fide offer for all gas described in this section, at some point in time after the contract expires, regardless of when the contract expired. The Commission's interpretation of section 315(b)(2) and (3), as requiring a bona fide offer for all gas to which this subsection applies, operates to give effect to both the language of the statute as written, and the intent of Congress as gleaned from the Conference Report.

4. *Timing of Bona Fide Offer.*— Section 277.205(b) of the proposed rule provided:

> (1) *Determination more than 45 days before contract expiration.* With respect to the natural gas subject to this subpart and for which the final determination that the natural gas qualifies as high-cost natural gas, new natural gas or gas from a new, onshore production well was made 45 days or more before the expiration date of the subject contract (other than a contract implied in law) the bona fide offer shall be made no later than 20 days prior to the expiration date of the subject contract.
>
> (2) *Determination less than 45 days before contract expiration.* In all other cases, the offer shall be made no later than 20 days after a final determination is made that the natural gas qualifies as high-cost natural gas, new natural gas or natural gas produced from any new, onshore production well.

Several persons commented that the bona fide offer should not be permitted to be made more than 18 months prior to the expiration of the contract. The commenters raising this point felt that without such a provision, the purchaser might find itself in the position of having to consider a bona fide offer years before the contract expires. Furthermore, years may elapse between the time the bona fide offer is made and the expiration of the right of first refusal. Such occurrences would circumvent meaningful compliance with the bona fide offer rule. Accordingly, the Commission has modified the proposal to provide that bona fide offers may not be made more than 18 months prior to expiration of the contract.

The commenters made several arguments that the 20-day time frame was unduly restrictive. One reason given was that negotiations between the parties often exceed 20 days, which, they suggested, is all the rule allows. The Commission believes that the 20 days provided for both the making and acceptance of the offer [§ 277.205(b)] is sufficient. While negotiations may or may not take longer than 20 days, that fact is immaterial here. Nothing in this rule limits the amount of time parties may carry on negotiations other than those required by the provisions regarding bona fide offers. The parties are free to enter into a contract for the sale of such gas where the contract was not the result of the procedures required regarding bona fide offers. In addition, the parties are also free to agree to modifications of the time requirements established in this rule. (*See,* § 277.209.)

The comments seem to imply that the time restrictions on making and accepting the bona fide offer work a hardship on small producers who may be unaware of the bona fide offer provisions, as well as a hardship on large producers who will find it difficult to monitor their contracts on a daily basis. One commenter noted that small producers may not be aware of these provisions, and that it would be preferable simply to require that the offer be made before the sale of gas under the subject contract is discontinued, or after a specified period of time following a request by the purchaser for a bona fide offer. The Commission does not accept these suggestions. Requiring that the bone fide offer provisions be complied with not later than 20 days before expiration of the contract is not significantly more burdensome to the small producer than simply requiring compliance before deliveries are terminated. Moreover, the 20 day notice provides protection to the purchaser which the Commission believes was intended in section 315(b)(2) since deliveries may not stop until the purchaser has had a reasonable opportunity to reject the bona fide offer.

Large producers were concerned that no provisions are made for the cases where the producer fails to comply with the time requirements of this section. Another commenter noted that in actual practice, contracts expire with no replacement contracts yet made. It was argued that it is not possible for purchasers with many contracts to monitor them on a daily basis. Such monitoring is not required by the rule. Sellers are free to make the bona fide offer at any time up to 18 months before the expiration of the contract. The flexibility afforded by the 18 month rule should result in no significant recordkeeping or monitoring burden on sellers. For instance, a seller could make an annual survey of interstate contracts, identify those expiring in the next 12 months for which well determinations have been made or applied for, and make bona fide offers to purchasers who are or may be entitled thereto.

The proposals to liberalize the time limits are not adopted.

5. *Acceptance or Rejection of the Bona Fide Offer.*—Section 277.205(c) stipulates the manner of making the bona fide offer and the acceptance thereof. This section provides that any counteroffer to the bona fide offer will constitute a rejection of the bona fide offer. One commenter suggested that for a counteroffer to act as rejection of the offer, it should be required to be in writing to avoid confusing counteroffers with requests for clarification of the bona fide offer itself. It was the intent of the Commission to treat only written counteroffers submitted in the manner of the required acceptance to be treated as the rejection of the offer. The text of the regulation has been so conformed.

Requiring written counteroffers is consistent with the Commission's position that nothing in this rule is intended to prevent the parties from negotiating for the continued sale of subject gas outside of the realm of the bona fide offer and right of first refusal rules.

Another commenter suggested that the Commission can establish that rejection of an offer will be implied after a certain time has elapsed. Section 277.205(c) of this rule, as well as the proposed rule, provides that if a bona fide offer is not accepted or rejected in the prescribed manner provided for therein, it will be deemed rejected.

B. Right of First Refusal

1. *General.*—Proposed § 277.206(a) contained the general rule governing the right of first refusal. The general rule provides:

> The seller shall present any offer substantially accepted in principle by a third person in an armslength transaction to the original purchaser for exercise of its right of first refusal. The offer shall be presented in accordance with the provisions of this section.

This provision engendered numerous comments. First, one commenter suggested that the contract which is submitted to the original purchaser should not be party-specific, that is, the name of the third-party purchaser should be omitted. The proposed rule did not require that the name of the third-party purchaser be disclosed.

One commenter suggested that the rule should specify that only sections 102, 103, and 107 gas is subject to the rule, and that the seller is still required to sell to the original purchaser all other gas previously committed or dedicated to it. The comment accurately reflects the provisions of section 601 of the NGPA and these regulations, however, we feel the applicability and definitions provisions in the rule (in § 277.202 and § 272.203(a)) adequately describe the scope of this rule. It was also suggested that the rule state that once the original purchaser refuses to accept the first offer substantially accepted in prinicple by a third-party, the provisions of section 315 will cease to apply to the subject natural gas. This suggestion is not accepted. The rule provides, in § 277.204, that the provisions cease to apply only if a sale is subsequently made under the terms rejected by the original purchaser. The rule is necessary in order to avoid the presentation to the original purchaser of offers which, while "substantially accepted in principle by a third party," were never intended to apply to an actual sale of the subject natural gas.

One commenter stated that it is not necessary to have fixed every detail of the "offer substantially accepted" by a third party. The offer should be flexible enough to enable negotiations to take place between the seller and original purchaser. The Commission believes that the offer must be sufficiently firm that when accepted by either the third-party purchaser, or the original purchaser, a binding contract would result. However, as noted above, the seller and original purchaser may agree to modify or supplement the terms found in this offer; indeed, the seller may be required to modify certain terms, such as delivery point and delivery pressure, where necessary to enable the original purchaser to accept delivery of the subject gas (see § 277.206(d)).

The final comment concerned the provision which prevents transactions between affiliates from being able to satisfy the right of first refusal obligations. The point made by the commenters here is that adequate safeguards exist to ensure that these transactions are fair, and section 601 of the NGPA allows the Commission to oversee such transactions. The commenters argued that because these safeguards exist, the affiliate transactions need not be prohibited, but can be permitted and reviewed by the Commission using a third-party standard. Inasmuch as the language of section 315 explicity requires that transactions be at arms-length, the Commission finds that affiliate transactions were not intended to be included in the scheme of the right of first refusal. The suggestions made by the commenters will not be adopted.

However, the final rule has been amended at § 277.209(a), to permit the original purchaser to waive the exclusion respecting affiliate transactions.

2. *Time Frame Proposed.*—The time frame for making and accepting the offer pursuant to the right of first refusal was set out in § 277.207(b) and (c). With

respect to this provision, one commenter indicated that it felt insufficient time was provided for the transmittal of the offer to the original purchaser. Proposed § 277.206(b) provided that the seller must present the offer at the later of (1) the time when the offer substantially accepted in principle by the third-party purchaser, or (2) the time when the bona fide offer is rejected. The Commission has amended this provision to permit the seller to present the offer within 10 days of its acceptance, or rejection of the bona fide offer, whichever is later.

One commenter stated that the use of certified mail for sending the offer to the original purchaser should not be required. Use of certified mail enables the parties to know with more certainty when the time periods for offer and response expire. Accordingly, disputes over the timeliness of actions are less likely to result. Telegrams with confirming copy sent by certified mail will be acceptable as they also tend to restrict disputes over timeliness.

3. *Delivery Point and Physical Conditions of Delivery.*—Section 277.206(d) of the proposed rule provided:

> *Delivery point under an accepted offer.* Notwithstanding any contrary provision of an offer substantially accepted in principle, the original purchaser that accepts the offer shall (at its option) have the right to receive the natural gas at the delivery point and under the physical conditions of delivery specified in the subject contract.

Three commenters took issue with the provisions of this section, based on the argument that the Commission is not authorized to prescribe the terms of delivery, and that the right to alter delivery point is outside of the realm of the right of first refusal. The parties stated that delivery point and other conditions of delivery have substantial economic impact and can thus affect the price agreed upon in the agreement between the seller and a third party purchaser. To enable the original purchaser to avoid these terms, they argued, subverts the negotiation process. Commenters insisted that the original purchaser should be required to accept *all* the terms of the offer substantially accepted by the third party.

The Commission fully recognizes that terms concerning delivery point and pressure affect the sale price for natural gas established in a contract. However, the Commission believes that in order to give the original purchaser a meaningful right of first refusal under section 315(b)(3), the original purchaser must be given the opportunity to purchase the gas on terms which will physically allow delivery. To simply grant the original purchaser the first chance to accept an offer, under which it would be physically impossible for him to accept delivery, affords the original purchaser no substantial protection at all. For example, the terms of the offer substantially accepted may provide for delivery of the gas at some location to which the original purchaser has no access. Unless the purchaser could obtain delivery at some acceptable location, his right of first refusal would serve no purpose.

If the original purchaser does accept an offer to sell natural gas made pursuant to section 315(b)(3), and makes changes in delivery conditions which place the seller in an economically disadvantageous position, the seller may petition the Commission for an allowance to compensate the seller for additional expenses incurred as a result of the original purchaser exercising the right to take delivery under the conditions in the subject contract.

C. Interim Protective Sales

Under the time provisions established in this rule, there is a potential gap between the subject contract's expiration and the original purchaser's acting on the bona fide offer. To provide for an orderly operation of section 315(b) as well as an orderly transition to non-price deregulation of natural gas subject to this rule, the Commission proposed provisions for interim protective sales. These provisions read:

§ 277.207 *Interim protective sales.*

(a) *General rule.* Except as provided in § 277.208, after the expiration date of a subject contract, any natural gas subject to the provisions of this subpart shall continue to be sold to the original purchaser until the requirements of § 277.205 (concerning bona fide offers) have been met.

(b) *Conditions of sale.* Natural gas sold to the original purchaser under paragraph (a) of this section shall be sold under the terms and conditions prevailing in the subject contract on the last day the contract was in effect, except that the seller may charge no more than the price paid by the original purchaser on the day before the final determination was made.

One commenter argued that interim sales are outside the scope of the Commission's jurisdiction, and so this provision should be deleted. This commenter further asserted that the price limit in paragraph (b) is unlawful, as the Commission cannot impose as a ceiling price the lower of two applicable maximum lawful prices, by operation of section 101(b)(5) of the NGPA. The Commission disagrees. It is within the scope of the Commission's rulemaking authority in implementing section 315(b) of the NGPA to impose on the seller an obligation to continue sales to the original purchaser (on terms prevailing under the expired contract), where the seller fails to comply with his duty to make a bona fide offer.

Another commenter suggested that instead of retaining the *price* in effect on a certain date, the *pricing terms* should be retained, in order to permit escalation. We agree. Section 277.207(b) is modified to provide that the seller will continue to sell the subject gas to the original purchaser in accordance with the pricing terms which were in effect on the last day the contract was effective, rather than limiting the price to the price paid by the original purchaser on the day before the final determination was made.

D. Intervening Third-Party Sales

The proposal contained provisions in § 277.208, regarding sales made to third parties prior to the issuance of the proposal. The proposal would have permitted the original purchaser to apply to the Commission for relief. One commenter recommended that the Commission clarify what terms would be available to the original purchaser seeking relief in the case in which the subject contract has expired and the seller has entered into a contract for the first sale of the subject gas after the gas received a final determination and before this rule was issued. Section 277.208(b) in the proposed rule provided that the original purchaser could apply for relief as the Commission would deem appropriate, and such application be made not later than January 15, 1980. The Commission does not believe it could fairly decide issues which will be raised in applications for relief except upon review and examination on a case-by-case basis. This provision is retained in the final rule. The date for such applications will be moved forward, and the new deadline for applications for relief will be September 1, 1980.

5. *Waivers.*—The proposed rule, at § 277.209, allowed the original purchaser to voluntarily waive its right to a bona fide offer or the right to first refusal and provided the manner in which to effect such a waiver. Several persons recommended deletion of this section. One argument made which favored deletion was that waiver is not warranted by section 315, and is contrary to the public interest. The obligations found in section 315 are statutory in nature and a seller cannot be relieved of these obligations. Another commenter stated that the Commission is nowhere empowered to authorize anticipatory waiver. A waiver by one purchaser could unfairly result in a waiver for all successor purchasers. A right cannot be waived, it is argued, until it may be exercised.

The Commission does not agree that waiver is either unwarranted or unauthorized. The Commission believes that the parties have the right to bargain for the waiver of section 315(b) rights irrespective of whether or not the rule contains the provisions concerning waiver. Moreover, if a purchaser is satisfied that his rights under section 315(b) are adequately protected through his own negotiations with the seller, the Commission perceives no reason to insist the seller should be required to execute the intricate procedures required under section 315(b). However, in response to the concerns raised, a new provision has been added in the final rule which requires that any waiver must be made no more than one year prior to the expiration of the subject contract.

A question was raised whether the waiver is intended to be a blanket waiver of all section 315(b) rights, or a contract-by-contract waiver. This commenter considered a blanket waiver to be unacceptable, because to make a knowing and voluntary waiver, the original purchaser must consider proposed terms and conditions for a specific contract for the purchase of a certain type of natural gas, in certain quantities, and at a given price. This commenter further asserted that any written waiver should be preceded by notice to the ultimate customers and the state regulatory agency. The customers and state agencies should have an opportunity to review and oppose such waivers.

Once again, it is the Commission's position that the scope of the waiver, whether blanket or contract-specific, is a matter to be agreed upon by the seller and original purchaser in arms-length transactions. A purchaser's agreement to a waiver of its rights to a bona fide offer or right of first refusal should not be subject to any different scrutiny than the failure to exercise those rights would be.

III. Summary of the Rule

The rule implementing the bona fide offer and right of first refusal provisions of section 315(b) of the NGPA are found in Subpart B of Part 277 of the Commission's regulations. Sections 277.201 through 277.204 are general in nature, setting forth the applicability, purpose and scope of the rule promulgated under section 315(b). The rule applies to natural gas which has been removed from Natural Gas Act jurisdiction by virtue of its being the subject of a final determination that it qualifies as deregulated high-cost gas under section 107(c)(1) through (4), new natural gas under section 102(c), or natural gas produced from any new, onshore production well under section 103(c) of the NGPA. The general rule requires that before a seller of the natural gas described above (hereinafter "subject gas") enters into a sale of the subject gas to a purchaser other than the purchaser who received the gas under the Natural Gas Act (the original purchaser), the seller must first make a bona fide offer of sale of the subject gas to the original purchaser. If the original purchaser rejects this bona fide offer, the seller may seek a third-party purchaser, but before any sale of the subject gas can be made to a third party, the seller must give the original purchaser the opportunity to purchase the subject gas at the terms and conditions substantially accepted in principle by the third-party purchaser. This describes the right of first refusal vested in the original purchaser by section 315(b)(3).

Section 277.205 establishes procedures and the time frame pursuant to which the bona fide offer required by section 315(b)(2) is to be made and accepted or rejected. In the case where the subject gas has received an appropriate final determination (that it qualifies under section 107(c)(1) through (4), section 102(c), or section 103(c)) 45 days or more before the subject contract expires, the seller must make the bona fide offer no later than 20 days before the contract expires. When the appropriate final determination is made less than 45 days before contract expiration, the bona fide offer is required to be made no later than 20 days after the subject gas is removed from the jurisdiction of the Natural Gas Act, that is, the date of the final determination. A bona fide offer cannot be made more than 18 months prior to the expiration of the contract covering subject gas, if it is to satisfy the requirements set out in the NGPA and the implementing regulations. The bona fide offer must be transmitted to the original purchaser in writing, and sent by U.S. mail, certified, return receipt requested. The original purchaser must respond to the offer within 20 days; any acceptance must be in writing and is deemed operative when signed and placed in the U.S. mail, certified, return receipt requested. Counteroffers and failure to respond are deemed to be rejections.

If the original purchaser rejects the bona fide offer, and the seller seeks to sell the gas after expiration of the subject contract, the right of first refusal comes into play. The procedures and time requirements for the implementation of the right of first refusal provisions are set forth in § 277.206. The seller is required to submit to the original purchaser the offer substantially accepted in principle by a third party in an arms-length transaction not later than 10 days from the later of the time when the offer was substantially accepted in principle, or the time when the bona fide offer was rejected. The offer must be sent by U.S. mail, certified, return receipt requested, and, if accepted, must be accepted by the original purchaser within 20 days of its receipt. Counteroffers or acceptances after 20 days have passed are deemed to be rejections. An acceptance is operative if it is in writing, when placed in the U.S. mail, certified, return receipt requested.

A significant provision is incorporated in the rule where it concerns the right of first refusal and is found in § 277.206(d). This provision enables the original purchaser, in the exercise of its right of first refusal, to accept the offer substantially accepted in principle and to modify the delivery point and physical conditions of delivery stated in this offer to match those in the subject contract between the seller and the original purchaser. The seller in this case may request that the price be increased to offset any additional cost incurred by the seller related to the original purchaser's decision to modify terms of delivery. The price may be increased by action of the Commission, but will not be raised above the applicable maximum lawful price.

First sales of natural gas subject to the section 315(b) requirements cease to be subject to these requirements when the original purchaser has both rejected the bona fide offer and the offer substantially accepted in principle by a third-party purchaser and the subject gas has been sold to a third-party purchaser pursuant to the terms of that offer rejected by the original purchaser.

Section 277.207(a) provides for interim protective sales to be carried out in the period after the subject contract has expired and until the seller has satisfied its obligation to make to a bona fide offer. Section 277.207 provides that such sales will be under the terms and conditions prevailing in the subject contract on the last day the contract was in effect. The rule also makes provisions, at § 277.208, for natural gas which has been removed from the Natural Gas Act jurisdiction before September 1, 1980. Original purchasers of this gas may apply for relief with the Commission not later than September 1, 1980. In general, requirements of bona fide offer and right of first refusal found in §§ 277.204 through 277.206 will not apply to this gas.

Original purchasers may waive the rights granted to them under section 315(b), pursuant to § 277.209 of the rule. In order to be effective, the waiver must be made no more than one year prior to the expiration of the subject contract, it must be in writing and signed by the original purchaser. The original purchaser is also specifically permitted to waive the prohibition which prevents affiliate transactions from being qualifying transactions for the purposes of obtaining an offer substantially accepted in principle by a third party, subject to the original purchaser's right of first refusal.

Section 277.210 requires that sellers subject to this subpart retain copies of all bona fide offers made under § 277.205, and offers made to original purchasers in compliance with such purchasers' right of first refusal under § 277.206. Sellers and purchasers are also required to retain all other documents related to this subpart which are created in the ordinary course of business.

IV. Effective Date

This rule shall become effective as a final rule on September 1, 1980.

(Department of Energy Organization Act, 42 U.S.C. §§ 7101–7352; E.O. 12009, 42 FR 46267; Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301–3432; Natural Gas Act, as amended 15 U.S.C. §§ 717–717w)

In consideration of the foregoing, Subpart B of Part 277, Chapter I, Title 18, Code of Federal Regulations is added, as set forth below, effective as a final rule on September 1, 1980. By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,180]

45 F. R. 53456 (August 12, 1980)

18 CFR Part 375

[Docket No. RM80-68; Order No. 97]

Amendment to Rules Relating to Delegation of the Commission's Authority of the Director of the Office of Pipeline and Producer Regulation

Issued August 1, 1980

AGENCY: Federal Energy Regulatory Commission.

ACTION: Amendment to regulations of delegation of authority.

SUMMARY: This order grants authority to the Director of the Office of Pipeline & Producer Regulation to issue as notices of proposed rulemaking, recommendations for designations of tight formations submitted to the Commission by jurisdictional agencies under § 271.705 of the Commission's rules.

EFFECTIVE DATE: August 1, 1980.

FOR FURTHER INFORMATION CONTACT: Leslie J. Lawner, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol St. NE., Washington, D.C. 20426. (202) 357-8027.

SUPPLEMENTARY INFORMATION:

A. Background

On August 4, 1978, the Commission approved a rulemaking, Delegations of Authority (Phase I) (August 17, 1978), Docket No. RM78-19 (43 FR 36433), which served to transfer decision-making authority over matters of a largely routine and ministerial nature to the Commission's various Office Directors, so that the Commission could concentrate its major efforts on matters where direction of policy was required. Subsequently, on July 23, 1979, the Commission added new delegations to the original ones, in the Phase II Delegation, Docket No. RM79-59 (44 FR 46449, August 8, 1979).

As a continuation of the process of delegating ministerial tasks to Office Directors, the Commission has decided to delegate further authority to the Director of the Office of Pipeline and Producer Regulation (OPPR).

The authority to be delegated to the Director of OPPR arises under section 107(c)(5) and section 501(a) of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. § 3317(c)(5) and § 3351(a)). Section 107(c)(5) authorizes the Commission to designate certain types of natural gas as high-cost gas, where the Commission has determined that such gas is produced under conditions which present extraordinary risks or costs. Pursuant to section 107(c)(5) and its general rulemaking authority under section 501(a), the Commission issued an Interim Rule in Docket No. RM79–76, High-Cost Gas Produced From Tight Formations.[1] In this rule, the Commission found that production of natural gas from tight formations presents extraordinary risks and costs and that such gas should be eligible for an incentive price. The Interim Rule prescribed guidelines to aid in the identification of those formations which are tight and from which production should receive the incentive price. It was also established in the Interim Rule that jurisdictional agencies, named in § 274.501 of the Commission's regulations (18 CFR 274.501), would be responsible for applying these guidelines to prospective tight formations and for forwarding their recommendations for tight formations to the Commission.

The Interim Rule established procedures pursuant to which jurisdictional agencies will submit to the Commission recommendations of areas for designation as tight formations. The procedures concerning these recommendations are found in § 271.705 of the Commission's regulations. Section 271.705(d) provides that upon receipt of a recommendation, the Commission shall publish in the **Federal Register** a notice of proposed rulemaking containing the recommendation. After reviewing the comments received in response to the proposed rule, the Commission will prescribe a rule approving or disapproving the recommendation. If the recommendation is approved, the Commission's regulations will be amended to add the newly designated formation to the list of other approved formations, which will appear in the regulations.

The Commission expects to receive approximately 150 such recommendations over the next three years, each recommendation necessitating a notice of proposed rulemaking and appropriate Commission action. Due to the large number of recommendations anticipated, the Commission believes that if it delegated to Staff, specifically the Director of OFPR, the authority to issue recommendations received as notices of proposed rulemaking, the process of designating formations would be expedited. It is hoped that this would result in a more rapid development of tight gas reserves.

B. Summary

Under new 18 CFR 375.307(m), there is delegated to the Director of the Office of Pipeline and Producer Regulation the authority to issue Notices of Proposed Rulemaking pursuant to § 271.705(d) containing recommendations, submitted by jurisdictional agencies, of formations to be designated as tight formations.

C. Effective Date

The Commission hereby makes this regulations effective upon the date of issuance of this order. The regulation concerns agency practice and procedure and internal agency management, accordingly, pursuant to the Administrative Procedure Act (5 U.S.C. § 553(b) and (d)), public notice and comment are not required, and the regulation may be made effective immediately upon issuance.

(Department of Energy Organization Act 42 U.S.C. 7107 *et seq.*, Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432))

For the reasons stated herein, Part 375 of Subchapter W of Chapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

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[1] Interim Rule in Docket No. RM79–76 issued February 20, 1980 (45 FR 13414, February 28, 1980.)

[¶ 30,181]

45 F. R. 54733 (August 18, 1980)

18 CFR Part 281

[Docket No. RM79-40; Order No. 55-B]

Natural Gas Curtailment; Final Regulations Governing the Determination of Alternative Fuels for Essential Agricultural Users and Finding of No Significant Impact

August 11, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final Regulations and Finding of No Significant Environmental Impact.

SUMMARY: The Commission is amending Part 281 of its regulations by amending Subparts B and C that prescribe which fuels the Commission has determined to be economically practicable and reasonably available as a substitute for the essential agricultural use of natural gas and how certain essential agricultural users of natural gas must change their priority 2 entitlements for those volumes of gas for which there is an alternative fuel. The rule applies only to: (1) Essential agricultural use establishments that have requested from any direct supplier, over 300 Mcf of natural gas per day as a priority 2 entitlement; and (2) new boilers with a capacity of 300 Mcf per day, except diesel engines and turbines that can only use distillate fuels as a substitute for natural gas. The application of the rule is limited to the use of coal or residual fuel oil as alternative fuels.

This rule is promulgated under section 401(b) of the Natural Gas Policy Act of 1978 which restricts the protection from curtailment afforded under the Act by excluding from that protection any gas applied to essential agricultural uses, where there are other economically practicable and reasonably available fuels for those uses.

Essential agricultural users, local distribution companies and interstate pipelines must revise their priority 2 entitlements only to the extent there have been changes from the previous year. Any changes must be reported by August 31, 1980. Under the final rule interstate pipelines will receive sufficient information from customers in the next six weeks to be able to amend their indices of entitlement to reflect the changes in priority 2 entitlements.

Revised indices must be filed by October 1, 1980.

The Commission has also made a finding that adoption of the final rule will have no significant environmental impact.

EFFECTIVE DATE: August 11, 1980.

FOR FURTHER INFORMATION CONTACT: MaryJane Reynolds, Federal Energy Regulatory Commission, Office of the General Counsel, 825 North Capitol St. NE., Washington, D.C. 20426, (202) 357-8455.

The Federal Energy Regulatory Commission (Commission) adopts final regulations that implement section 401(b) of the Natural Gas Policy Act of 1978 (NGPA) by establishing a generic alternative fuel determination for essential agricultural users and by updating filing requirements for natural gas curtailment plans that are affected by priority 2 (essential agricultural) uses of natural gas.

I. Background

On June 3, 1980, the Commission issued a notice of proposed rulemaking (the "June 3 notice") in this proceeding (45 FR 38283, June 10, 1980). The notice proposed implementation of a final rule pursuant to section 401(b) of the Natural Gas Policy Act (NGPA), to replace the interim rule promulgated by Order No. 55 on October 26, 1979.

Order No. 55 established that alternative fuel determinations under section 401(b)[1] would be made generically rather than case-by-case.[2] In that rule the Commission determined that, for the 1979–1980 heating season, only coal and residual fuel oil were reasonably available and economically practicable for essential agricultural users with requirements exceeding 300 Mcf per day. In addition, new boilers with a capacity in excess of 300 Mcf per day were deemed to have alternative fuel capability.

In the June 3 notice, the Commission proposed a final rule retaining the procedural features of the interim rule. The notice further provided that residual oil and coal would be determined to be reasonably available and economically practicable as alternative fuels. The Commission indicated that although the rule would be considered final, it would be subject to future amendment as circumstances might require.[3]

The statute requires that a rule implementing section 401(b) be made only after consultation with the Secretary of Agriculture. The Commission has consulted with the Department of Agriculture and its comments have been placed in the public files of this proceeding. In addition, a representative of the Department of Agriculture served as a member of the panel designated by the Chairman of the Commission to conduct a public hearing on the proposed rule.

The Commission appreciates the efforts of the Department of Agriculture in developing a full and sound decisional record and providing the Commission with comments and advice that have been given careful consideration. However, we must reject the position of one commentor who argued that the views of the Department of Agriculture must be accommodated unless they are clearly erroneous. No legal authority was cited for this "clearly erroneous" test. The Commission, not the Department of Agriculture, is ultimately responsible for implementing section 401(b). The statutory requirement for consultation is not synonymous with a joint rule fully agreed upon by both the Commission and the Secretary of Agriculture.

Upon consideration of the comments received in this proceeding as well as the record in the interim rule, the Commission has determined to adopt the rule proposed in the June 3 notice as a final rule, with certain minor changes.

Residual fuel oil and coal will continue to be viewed as reasonably available and economically practicable alternatives to natural gas. Aside from technical changes, the only change from the proposed rule is that the proposal to exempt small users on the basis of *peak* day requirements will be deleted. The provision of the interim rule exempting small users with requirements of 300 Mcf per day will be retained. By the deletion of the word "peak" from the 300 Mcf per day limitation as proposed, the Commission intends that the 300 Mcf per day limitation be implemented in the same manner as was done during the past year.

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[1] Section 401(a) of the NGPA provides that essential agricultural uses of natural gas may not be curtailed except to the extent necessary to meet high priority uses. Section 401(b), however, provides that the curtailment status of section 401(a) shall not apply to those essential agricultural users for which the Commission, in consultation with the Secretary of Agriculture, determines that an alternative fuel is reasonably available and economically practicable.

[2] The Commission had earlier proposed a case-by-case approach. The overwhelming response to the Notice of Proposed Rulemaking favored a generic procedure. The Commission accepted the arguments that a generic rather than a case-by-case procedure is persuasive, and Order No. 55 resulted. (See discussion below.)

[3] As indicated in Order No. 55, any changes, would, if possible, not be made during any winter heating season.

We recognize that a rule which may be changed due to changing circumstances makes long term planning more difficult. However, the NGPA is a new statute. It has created a new program and imposes a new alternative fuel test which the Commission believes requires consideration of circumstances, as they exist from time to time, for its proper implementation.

II. Discussion of the Major Issues

A. Introduction

The issues raised in the comments on the proposed rule are in large part the same as those raised concerning the interim rule. The Commission has reviewed them but is not persuaded that it should change the positions expressed in Order No. 55. To the extent the issues are the same, the explanations given in Order No. 55 also apply to the arguments presented in the present proceeding.

B. Economic Practicability

The most difficult issues facing the Commission in this rulemaking is how to interpret the Congressional phrase "economically practicable alternative." The Congress established a special priority for agricultural users of natural gas in order, the Statement of Managers states, "to prevent unnecessary increases in the cost of food in this country." Congress provided that the Commission could deny this priority to users with an economically practicable alternative. Again, consistent with Congress basic concern about increases in the cost of food and fiber, the Statement of Managers states that the intention was not to require agricultural gas users to switch to a "high cost alternative."

Some agricultural users who want to protect their priority 2 classification would translate "economic practicability" into a simple test of comparing natural gas prices with prices of possible substitute fuels. They would say the substitute fuel is economically practicable only if it is equal to or less than the price of natural gas. Other essential agricultural users, however, suggest that a substitute fuel may be economically practicable so long as its price is within some reasonable range of the price of natural gas.

To industrial process and feedstock users, interested in keeping priority 2 as small as possible because their requirements are curtailed immediately before those in priority 2, "economic practicability" represents the other extreme on the spectrum of construction. They note that § 402 (the NGPA priority 3 protection for essential industrial process and feedstock users) also imposes an alternative fuel test. It, too, is based on economic practicability (and reasonable availability). The Statement of Managers indicates that in the context of § 402 economic practicability means the "economic feasibility" standard of the Federal Power Commission ("FPC") under extraordinary relief proceedings seeking waiver from curtailment. The advocates of this position do not articulate a specific test for determination of "economic feasibility." However, they appear to seek to limit the test to the economic feasibility of installing conversion facilities to use a fuel other than natural gas. To this end, the cost of the alternative fuel itself would be irrelevant. Cost of conversion would control.

Under the test proposed by the industrial process and feedstock users, substitute liquid fuel,[4] at any price, would be economically practicable for any essential agricultural user with installed alternative fuel capability. Some would go beyond this to say alternative fuel would also be economically practicable for additional essential agricultural users if the cost of conversion were "economically feasible."

As this brief summary indicates the statutory term "economically practicable" is not clear on its face, and the Commission must construe it and shall do so in a manner which will best comply with the overall statutory scheme embodied in Title IV of the NGPA. The Commission does not believe the proposed construction of either side gives consideration to the full intent of Congress. Numerous aspects of energy costs affect food prices in this country in a complex way. A precise estimate of the impact of using an alternative fuel would require a determination or not only the increase in energy cost but also the extent to which other production factors (*e.g.* capital and labor) could be substituted. We would also have to know how much of the increased cost could be passed through to consumers considering the elasticities of demand. This can be done with precision only on a facility-by-facility basis. The Commission first proposed a procedure along these lines for purposes of implementation of the interim rule. 44 FR 26894 (May 9, 1979). There was near unanimous opposition to such case-by-case analysis and decisionmaking. The required data submissions by essential agricultural users appeared burdensome. There was also concern that individual determinations would unduly delay implementation of the alternative fuel rule.

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[4] At least one essential process and feedstock user recognizes the potential economic disruption its construction could visit upon essential agricultural users. PGC suggests synthetic fuels might not be considered economically practicable because of the cost. However, PGC fails to explain how cost of fuel would be applied in its economic feasibility test. (Hearing transcript, June 30, 1980, p. 138.)

As part of finding some meaningful but workable operational definition of "economically practicable" the Commission has the difficult task of interpreting the terms "unnecessary increases in food costs," and "high cost alternatives". Even with precise facility-specific measures of output cost impacts as a result in the change in the cost of energy inputs, the Commission would still have to determine if the increases were "unnecessary" or the alternative fuel was "high cost."

With this legislative context in mind, we now consider how the various potential constructions of the alternative fuel exemption would affect the priority 2 classification established by Title IV. The position that any fuel more expensive than natural gas is not economically practicable, based on the data contained in this record, would result in no liquid fuel qualifying as an alternative fuel. Except for those few uses of coal, agricultural users would be given priority 2 treatment for all their requirements and the alternative fuel exemption would be largely meaningless. We do not believe Congress intended the alternative fuel rule to be so limited as to be illusory. Certainly, if the intent of the Congress was to limit alternative fuels to those that cost less than gas, it could have reached the result with simpler and clearer language.

Liquid fuel prices exceeded natural gas prices when the Natural Gas Policy Act was passed. (Appendix A; June 3 notice, Appendices A and B, Charts 2–3.) A major concern leading to passage of Title I of the NGPA was the need to increase domestic production of natural gas. The shortage in natural gas supplies had manifested itself in natural gas curtailments every year since the beginning of the 1970's and curtailment was projected for the winter heating season 1978–1979.[5] In sum, at the time the NGPA was passed all liquid fuel prices including those to agricultural users exceeded natural gas prices, and natural gas customers including essential agricultural users were experiencing curtailment. It was in this context that Congress said use of an alternative fuel should not cause "unnecessary increases in the cost of food in this country." Read in this light, the agricultural users are actually advocating that the alternative fuel rule must be construed to reduce their energy costs. Specifically, if economic practicability were measured as "equal to or less than natural gas costs" all essential agricultural users would have been entitled to priority 2 because all liquid fuels exceeded natural gas prices when the NGPA was passed.[6] Subsequent price increases in liquid fuels would be irrelevant. Thus, they could have substituted natural gas (even if liquid fuel prices remained constant). This would have *reduced* their energy costs. If such were the intent, why would Congress have expressed concern about unnecessary *increases*? Some users might suggest that only increases above fuel oil prices in effect when the NGPA was passed give rise to the "economic practicability" bar. However, these essential agricultural users fail to recognize that such a rule, in the face of decreased curtailment, could also lead to a reduction in the cost of energy.

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[5] Indeed, the record in this proceeding shows that curtailment was approximately 20% in the winter heating season 1978–1979.

[6] We also note that to the extent essential agricultural users were using alternative fuels they were incurring, in certain situations, additional costs associated with handling the alternative fuel.

The Commission is unable to accept a construction which implies that Congress was unmindful that fuel is only one of many costs involved in the cost of food. It is equally unable to accept a construction which ignores the level of curtailment—which is directly related to the amount of alternative fuel required and therefore to the energy cost component of food.[7] In reaching this conclusion we are aware that Congress admonished against requiring the switch to high cost alternatives. However we do believe this language must be given meaning in the context of the impact that use of high cost fuel would have on the cost of food and after projected curtailment levels have been factored in.

The economic feasibility test, advocated by process and feedstock users, yields a result as extreme, albeit opposite, as the result advocated by the agricultural users. It would have all essential agricultural users with installed capability[8] excluded from priority 2. Such a test ignores the cost of fuels in its entirety. We believe Congress intended to create a preference for agricultural users when it passed § 401. Use of the economic feasibility test would return most essential agricultural users to their pre-NGPA curtailment priority. It would render § 401 virtually meaningless.

A determination of "unnecessary increases" in costs requires discretion which is best exercised in light of prevailing circumstances. It requires a balancing of the economic risks a particular construction would have upon the various users of natural gas. Given the present situation we believe we should consider the extent to which agricultural users of natural gas are likely to be curtailed. The level of curtailment has decreased for the past several winter heating seasons.

Annual Natural Gas Curtailments

[April through the following March]

Year	Volume (in MMcf)[1]
1976-77	3,853,886
1977-78	3,655,279
1978-79	3,128,952
1979-80	1,606,474
1980-81 (projected)	1,242,770

[1] Excludes pipeline to pipeline curtailments. Source: Form 16's of major interstate pipelines.

Our present projections indicate approximately 8% curtailment for the 1980–1981 winter heating season. This means that the amount of time an essential agricultural user which will lose priority 2 classification will have to use an alternative fuel, because of inability of pipelines to serve all customers, is likely to be small. On an annual basis, deliveries for residential, commercial and firm industrial users (roughly corresponding to curtailment priorities one, two and three) range between 70 and 75 percent of total deliveries to end-users.[9] The remainder are below priority 3 and generally serve various categories of boiler fuel requirements. Thus, it is unlikely that for this winter heating season process and feedstock users will experience significant curtailment caused by supply shortages. Therefore the alternative fuel question is reduced to a question of whether agricultural boilers should be given a preference over other industrial boilers. We believe agricultural users with No. 2 oil and propane as their only alternatives should be given such a preference over other boiler users but users with other alternative fuels should not.

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[7] Some commentors suggest that the additional cost of handling alternative fuel is also relevant. We agree that there may indeed be additional costs. However, we lack record data that under the present circumstances there have been substantial increases in handling costs of alternative fuels.

[8] The economic feasibility test may exclude additional essential agricultural users if the installation of alternative fuel capability is determined to be economically feasible. Such determinations could inordinately delay implementation of the alternative fuel rule.

No. 2 oil is the most expensive of the alternative liquid fuels. Its price almost doubled in 1979. We cannot predict the rate of increase in 1980.[10] However, under the circumstances, we believe the risk of additional increases in No. 2 oil prices is an unnecessary one to impose upon essential agricultural users. These considerations lead the Commission to decline to exercise its discretion to determine No. 2 oil to be an economically practicable alternative.

Propane prices appear to be generally higher than those of No. 2 oil. The same considerations lead the Commission to decline to find propane to be an economically practicable fuel.

The question of the economic practicability of low sulphur No. 6 oil is more difficult. The data show it is generally less expensive than No. 2 oil but more expensive than high sulfur No. 6 oil. For the years 1976–1979 Monthly Energy Review data indicates the price differential between low sulphur No. 6 and No. 2 fuel oil relative to the natural gas price shows that low sulphur No. 6 was 27% to 40% less expensive than No. 2 oil. The Form 423 data indicates these differentials are 21% to 30%. (Appendix A hereto.) The data also indicates that No. 6 oil has not increased in price as rapidly as No. 2 oil, and the gap between the prices of No. 2 and low sulphur No. 6 is widening.[11] We must also be mindful that curtailment levels are decreasing. These factors lead us to conclude that treating low sulphur No. 6 as an alternative fuel would impose a lesser economic risk on essential agricultural users. Accordingly, we believe that low sulphur No. 6 is economically practicable. It follows that high sulphur No. 6 is also economically practicable.

We realize that this rule does not apply to existing facilities which have not installed alternative fuel capability. Some persons have argued that the result of this rule is to create a preference for those users which have not chosen to install alternative fuel capability. We do not deny that such a preference is reflected in our rule. But we believe imposition of conversion costs could cause unnecessary increases in food costs in the face of current gas supply projections. Therefore, we believe this preference is outweighed by the increases in costs that could be associated with conversion.

C. Reasonable Availability

As indicated in the June 3 notice, recent data published by DOE indicate that stocks for both residual and distillate fuel oil have been well above the level usually considered acceptable.

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[9] "Future Gas Consumption of the United States," Gas Requirements Committee, published by the University of Denver Research Institute, Volume 6, December 1975, Table A–5 and "Supplement to Volume 6," September 1976, Table 3; See also American Gas Association *Gas Facts* (1978), Tables 64 and 69.

[10] We wish to clarify that the inclusion of price data for January 1980 in the Notice of Proposed Rulemaking was solely for the purpose of providing the public with all the information available to the Commission at the time the notice was issued. However, the Commission does not believe it is appropriate to evaulate and project on the basis of data from a single month. Moreover, the Commission does not believe it is appropriate to compare monthly data with annual data because of seasonal and other short term price variability.

[11] In reaching this conclusion we are not unaware of the price increases in low sulphur No. 6 oil in January 1980. (June 3 notice, Appendix A) However, we do not believe it is appropriate to base decisions on data for only one month.

Many agricultural users, however, argue that our nation's reliance on imported oil makes supplies subject to sudden disruptions. Supplies are also said to be affected by such unpredictable factors as the weather, curtailment levels, oil prices, conservation, and changes in the economy. Consequently, these persons argue, neither distillate nor residual oil may be considered reasonably available. Instead of relying on present fuel inventories, they say, the Commission must consider the projected availability of these fuels. Others say that finding fuel oil reasonably available would be inconsistent with the fuel oil displacement program expressed in FERC Order Nos. 30[12] and 30–A[13] as well as with the goal of minimizing our dependence on foreign oil.

We do not find these arguments persuasive. Neither the statute nor the Statement of Managers qualifies the term "reasonably available" with references to long-term availability.

Moreover, Congress clearly intended to protect essential industrial process and feedstock users from curtailment, albeit in a priority lower than agricultural users. In our view, it is implausible to conclude that Congress intended to expose these process and feedstock users to curtailment when alternative fuel is available to agricultural users simply because these fuels might become unavailable at some time in the future.

Our determination that liquid fuel oil is reasonably available for essential agricultural users does not conflict with the oil displacement program or the goal of reducing our dependence on foreign oil. The oil displacement program had at the time of adoption a two-fold basis: shortage of residual fuel oil and No. 2 oil as well as a need to reduce dependence on foreign oils. The Commission is considering continuation of the rule.

Continuation of the oil displacement rule, in light of current circumstances, may appropriately be based solely on the need to reduce dependence on foreign oil. Moreover, it is highly unlikely that this rule will alter the total amount of gas and oil consumed in this country. At issue here is only the question of whether certain agricultural users or other industrial users will be required to utilize the alternative fuel.

United Gas Pipeline Company (United) urges that determinations of reasonable availability be made by means of "a relief mechanism whereby any customer actually deprived of alternate fuel would obtain relief from its supplying pipeline or distributor."

United does not provide details concerning how such a plan would work. In any event, determining the availability of fuels by means of individual requests for relief would have the same disadvantages as the case by case approach to section 401(b), which we have considered previously and rejected.[14] In dismissing United's proposal as a rule of general applicability, we express no view on whether or not such an approach would be considered appropriate for an individual pipeline as a result of a petition for relief under section 502(c).

There was no significant debate on the availability of coal on a national level to those capable of using it.[15]

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[12] Docket No. RM79–34, May 17, 1979 (44 FR 30323, May 25, 1979).

[13] Docket No. RM79–34, September 12, 1979 (44 FR 54472, September 20, 1979).

[14] *See* Notice of Proposed Rulemaking, Docket No. RM79–40, August 29, 1979.

[15] One person alleges that coal is not reasonably available in California. The rule itself does not provide for circumstances that may affect individuals in certain regions. Unique circumstances are appropriately addressed in an adjustment proceeding.

Based upon the record, we find that coal and residual fuel oil are reasonably available fuels within the meaning of section 401(b).[16]

D. Adequacy of Data

The Commission has studied data from Form 423 and EIA data in connection with this rulemaking. The public data were summarized in the June 3 notice and public comment on these data solicited. Comments indicate that these sources may reflect large users who may enjoy lower prices than certain essential agricultural users.

Nobody however, has suggested an alternate source of data that more accurately measures costs to essential agricultural users. Nor is it apparent that data more directly focused on agricultural consumers would suggest different policy outcomes from those suggested by the Form 423 and EIA data.

Other comments indicate individual users have experienced prices that exceed those prices summarized in our June 3 notice. This is to be expected with any data set that is a composite of various reports from various sources. It does not however mean that the data are inappropriate for the general use made of them by the Commission. We have used the best data available and sought improved data. Even with more precise generic data of the sort advocated by some commentors, as we have previously stated, a highly accurate evaluation of impacts can be made only in a case-by-case determination, not in a rule of general applicability. Considering the inherent generality implied by a generic approach, we believe that the available data are adequate and the comments do not persuade us that further search for more precise generic series would be cost-effective.

E. New Boilers

Some commentors object to our exclusion of new boilers which are presumed to have alternative fuel capability. However, a contrary rule would remove incentives to install alternative fuel capability. This would not be sound public policy, and there is no indication that Congress intended such a result.

We are aware that the curtailment priority treatment by this Commission is not the only factor that may enter into a decision concerning alternative fuel capability on a new or replacement boiler. However, where an adjustment request established that the sole reason for installation of such capacity would be the operation of our rule, we believe it would be appropriate to consider the cost of such additional facilities and whether the incurring of such cost would cause unnecessary increases in the cost of food.

Several commentors oppose using the nameplate rated capacity to exempt boilers below 300 Mcf per day from an alternative fuel test. Some also object to using 16 hours as a measure of the capacity (expressed in MMBtu per hour). It is argued that boilers frequently are not used at full capacity and may be used for periods more or less than 16 hours.

We realize that actual use is not necessarily the same as nameplate rating and that boilers operate for periods other than 16 hours. Nevertheless, the use of nameplate capacity is an objective, verifiable, and administratively practicable method for excluding boilers below a certain size from operation of § 281.304(b) of the rule, which applies only to new boilers. Furthermore, it is often considered inefficient to limit a boiler's operation to 8 hours a day. Thus, 16 hours was selected as a reasonable, practical, middle ground.

F. Adjustments

A rule of general applicability cannot anticipate and accommodate every peculiar fact situation confronted by each person subject to the rule. We also realize that some users' actual experience will differ from the generalizations upon which the rule is base.[17] The impact of the rule on a particular user may give rise to a situation which warrants adjustment relief. Procedures for adjustments are available under 18 CFR 1.41.

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[16] Since we have not been able to find that distillate fuel oil and propane are economically practicable, we need not determine whether they are reasonably available.

In addition to the comments concerning regional availability and practicability of various fuels, a number of persons urged that the rule should provide for special problems faced by certain industries. Central Florida Gas Corporation, for instance, urges special protection for seasonal agricultural users against heavy curtailment at the height of their seasonal use. National Grain and Feed Association alleges that use of fuel oil in grain drying contaminates the grain because grain drying is a direct flame application. Likewise, National Milk Producers Federation says that use of fuel oil in mild processing results in an inferior product.

Our notice invited comment on the need and advisability of regional determinations of economical practicability and reasonable availability. Some persons advocated regional determinations. However, they provided little supporting data. Upon consideration of the available published data and the views and comments provided us, we do not believe an adequate basis exists for a regional rule at this time. One difficulty is the availability of regional data in the detail that could be desirable. For example, the inventory data published by the Economic Regulatory Administration shows availability on a national basis with reference to the "estimated minimum acceptable level," but ERA does not provide regional estimates of minimum acceptable levels. Our experience with curtailment cases suggests that to collect sufficient data to implement a rule based on regional considerations or tailored to individual industries would be a major task. We do not believe such a delay in implementing section 401(b) in order to implement a regional plan would be warranted by the likely advantages relative to a national rule.

G. Periodic Reconsideration of the Rule

A number of persons noted that conditions of price and availability can change rapidly and cannot be accurately predicted over a long period of time. Some urged the Commission to reevaluate frequently any rule adopted. Others suggested that a series of interim rules would be preferable. Several persons urged the Commission to adopt a methodology that would be useful indefinitely without requiring periodic review. Still others noted that deep curtailments are not anticipated for the approaching heating season and urged the Commission not to adopt any rule until further data could be obtained.

The NGPA was enacted in 1978. We do not believe that our duties under that law permit further delay in promulgating a final rule under section 401(b). Moreover, for reasons previously discussed, we have decided not to adopt a fixed formula for determining when alternative fuels are reasonably available and economically practicable.

Accordingly, we will endeavor to reconsider the rule adopted herein as changed circumstances may require, even though it is established as a final rule. We will also attempt, to the maximum extent practicable, to implement any required changes in time to allow adequate planning for future heating seasons. In any event, we do not anticipate changing the rule before the end of the 1980–1981 winter heating season.

H. The impact of this rule on other provisions in the NGPA.

Title II of the NGPA excludes from incremental pricing those essential agricultural users which do not have alternative fuel. The term is defined as fuel which is economically practicable and reasonably available. NGPA Section 206(b)(2). The Commission expects to issue a notice of proposed rulemaking in a separate docket in the near future which will seek comment on the appropriate alternative fuel test for purposes of incremental pricing. A number of people have commented in this proceeding (Docket No. RM79-40) concerning the application of this rule to incremental pricing. The Commission has not addressed the question of incremental pricing in this docket and will not do so. Rather it will reach a determination on the appropriate alternative fuel rule for Section 206(b) following further rulemaking proceedings.

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[17] For example, we are aware that the record indicates the cost of fuels to individual users differs from the costs published in the June 3 notice.

Similarly, many persons have commented that the alternative fuel test for Section 402 is also one of economic practicability and reasonable availability. They urge that the same test must be applied to Section 401 and 402. However the Commission has just recently taken referral of the rule proposed by the Economic Regulatory Administration for implementation of Section 402. See Docket No. RM80-67. No rule has yet been issued establishing a priority 3 for essential industrial users and process users. Such a rule must be adopted by ERA before the Commission implements the Section 402 alternative fuel rule. Accordingly, the meaning of the alternative fuel rule in Section 402 is not before the Commission at this time, and it would be inappropriate to attempt to construe its meaning in the context of this discussion of Section 401.

I. The Environmental Assessment

In an environmental assessment of the proposed rule, Staff concluded that the effects of the rule on air quality would be insignificant and the effects on agricultural costs of production would be small. The assessment was made available to the public in the Commission's Office of Public Information and comments were invited.

Staff's environmental assessment is predicated on the assumption that curtailments will be no worse than in the 1978–1979 heating season. Certain persons object to the use of the 1978–1979 curtailment levels and argue that the 1976–1977 levels, or even 100 percent curtailment, should be assumed. We do not agree. As shown in the table below, the 1976–1977 year was a watershed for curtailment, and included the coldest winter in fifty years. Although the 1978–1979 heating season is not the year of highest curtailment, nonetheless, substantial curtailment did occur that year as well, certainly signficantly more curtailment than occurred during the 1979–1980 year or than is projected for 1980–1981.

Annual Natural Gas Curtailments

[April through the following March]

Year	Volume (in MMcf)[1]
1973–74	1,399,444
1974–75	2,209,002
1975–76	3,130,260
1976–77	3,853,886
1977–78	3,655,279
1978–79	3,128,952
1979–80	1,606,474
1980–81 (projected)	1,242,770

[1] Excludes pipeline to pipeline curtailments. Source: Form 16's of major interstate pipelines.

Moreover, several of the problems experienced by pipelines during 1976–1977 have been mitigated by the construction of additional pipeline capacity and by the development of more storage facilities. Finally, the passage of the NGPA has made significant volumes of additional supply available to the interstate market, at least in the near term. The suggestion that analysis of the proposed rule should be based on 100 percent curtailment of natural gas bears no relation to anything that is likely to occur in the reasonably foreseeable future. The curtailment level experienced during the 1978–1979 winter is an appropriate assumption to include in the environmental analysis.

National Council of Farmers Cooperatives incorrectly alleges that Staff failed to consider the effect on nonagricultural users of finding that no alternative fuel is economically practicable and reasonably available.

Staff considered this alternative (Environmental Assessment at 19–20) and concluded that under such a rule, nonagricultural users could be more severely effected than agricultural users would be under the proposed rule.

Based on Staff's environmental assessment, the Commission finds that the rule adopted herein does not constitute a major federal action significantly affecting the environment.

J. Other Issues

Two persons requested that the rule be clarified to indicate that priority 2 status may be retained for those users of natural gas for which an agricultural user cannot use alternative fuels, even though the user has the ability to use alternative fuel for other uses at the same establishment. The interim rule was so clarified.[18] The rule adopted herein retains those features of the interim rule not specifically amended.

IV. Section-by-Section Summary of the Amendments

Definitions and cross references (§ 281.203). Section 281.203(a)(17), which defines "currently effective curtailment plan" is revoked. The phrase is now self-explanatory because the March 1, 1979 date is no longer relevant in describing existing plans.

Tariff filing requirements (§ 281.204). Section 281.204(b)(3) provides that the index of entitlements shall not include the volumes of natural gas for which the essential agricultural user has the ability to use an alternative fuel as determined under Subpart C. Under the interim rule, each interstate pipeline was required to amend its index of entitlements to remove from the priority 2 classification and place in an appropriate priority of service category "any volumes of natural gas included in any index of entitlements that is effective on October 31, 1979 (or on November 30, 1979, if the pipeline elects to file tariff sheets under paragraph (a)(2) of this section)." Under this final rule, a pipeline is required to amend its index of entitlements "pursuant to paragraph (b)(2)" to remove from the priority 2 classification and place in an appropriate priority of service category any volumes of natural gas for which the user has an ability to use alternative fuel if such volumes are included in any index of entitlements that is effective on or after October 31, 1979.

A new § 281.204(b)(4) is added to provide an optional deadline for revising indexes of entitlement in 1980 to accommodate alternate fuel capabilities.

Notwithstanding anything in paragraph (b)(2) (periodic update of the index of entitlements), a pipeline may elect to file its revised index of entitlements on November 1, 1980, with a proposed effective date December 1, 1980, if the pipeline files with the Commission's Secretary by October 1, 1980 a written notice of its decision to file its revised index on November 1, 1980, and also continues its existing index in effect until December 1, 1980.

Filing and documentation (§ 281.211). Section 281.211(b)(1)(ii)(D) is amended to provide that a request for classification of any essential agricultural requirement as a priority 2 entitlement shall include, with respect to any agricultural user to which Subpart C (alternative fuel determinations) applies, the data and calculations necessary to determine alternative fuel volumes under § 281.304.

Section 281.211 is amended to provide that for years subsequent to 1979, the data required by this paragraph must be filed only to the extent that there has been a change in essential agricultural requirements. This amendment makes it clear that changes resulting in reduced agricultural requirements must be filed, as well as requests for changes reflecting increased requirements.

Filing and service dates for 1980 (§ 281.216). Section 281.216 is amended by designating the existing paragraph [19] as paragraph (a) and by adding a new paragraph (b) to provide that if the pipeline elects to file its revised index of entitlements on November 1, 1980, under § 281.204(b)(4), the Data Verification Committee shall submit its report by October 23, 1980.

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[18] Order No. 55-A, Docket No. RM79-40, Order Denying Rehearing, February 19, 1980, at 5–6.

Definitions (§ 281.303). Section 281.303(a) of the interim rule defined "ability to use" an alternative fuel as meaning that an essential agricultural use establishment had, on August 29, 1979, the installed physical capability to use the alternative fuel and used that alternative fuel, in any amount, at any time after 1973, for an essential agricultural use. The final rule amends this definition by inserting the phrase "or thereafter acquired" after "on August 29, 1979." A similar change is made in § 281.304(a)(2).

Section 281.303(h) defined "essential agricultural requirements" to mean volumes of natural gas certified by the Secretary of Agriculture and calculated in accordance with 7 CFR 2900.4. This section is clarified by adding the words "and § 281.208(b) of this Part" to the end of the sentence.

Filing of amendments to essential agricultural requirements and priority 2 entitlements (§ 281.305). Under Order No. 55, this section provided for filing amendments to priority 2 entitlements to reflect alternative fuel volumes. Since that process has been completed, § 281.305 (a), (b)(2), (c), and (d) are no longer necessary and are deleted. The section is now entitled "General Rule." Existing paragraph (b)(1) is revised and made the general rule. It provides that any essential agricultural user subject to this subpart that has requested from any direct supplier priority 2 classification for volumes for any essential agricultural use establishment shall reduce its essential agricultural requirements calculated under § 281.208 to reflect the exclusion of volumes of natural gas for which its essential agricultural establishment has alternative fuel volumes under § 281.304.

V. Effective Date

These regulations are being issued effective immediately. The Commission finds good cause to waive the 30-day delay in the effective date under section 553 of the Administrative Procedure Act. In order that the interstate pipelines have sufficient opportunity to amend the indices of entitlements by the winter season, data on alternative fuels must be requested and transmitted to the pipelines in the next few weeks. In a curtailment situation, permitting priority 2 natural gas to be used this winter by essential agricultural users that are able to use an alternative fuel, as defined in § 281.303, could jeopardize the availability of natural gas to process and feedstock users that do not have the ability to use alternative fuels.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432; Department of Energy Organization Act, 42 U.S.C. 7101–7352; E.O. 12009, 42 FR 46267.)

In consideration of the foregoing, Part 281, Chapter I of Title 18, Code of Federal Regulations is amended as set forth below, effective immediately.

By the Commission. Chairman Curtis voted present.

Kenneth F. Plumb,
Secretary.

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[19] Contemporaneously with the Notice of Proposed Rulemaking issued in this proceeding on June 3, 1980, the Commission issued a rule in Docket No. RM79–15 adding a new § 281.216(a). The rule provides that under Subpart B filing and service dates for 1980 shall be the same as for 1979, notwithstanding anything to the contrary in § 281.212(d) or § 281.213(c).

Appendix A.[1]—*Comparison of Selected Fuel Price Data, FPC Form No. 423 versus Monthly Energy Review, 1976—January 1980*

Type of fuel	FPC form No. 423 price data [1]					Monthly energy review price data [2]				
	1976	1977	1978	1979	Jan. 1980	1976	1977	1978	1979	Jan. 1980
	Cents per MMBtu									
Fuel Oil:										
No. 2	235.1	264.3	271.9	402.1	564.4	226.4	257.3	268.2	403.1	537.2
Low Sulfur No. 6	207.1	229.1	225.1	320.2	453.3	193.6	221.3	216.8	322.4	466.5
High Sulfur No. 6	168.7	199.9	186.7	264.7	361.4	165.9	195.2	186.1	261.5	349.6
All No. 6	195.9	220.4	212.3	299.7	423.5	182.6	210.4	202.7	297.0	417.7
Coal: All Grades	84.8	94.7	111.6	122.4	128.7	(3)	(3)	(3)	(3)	(3)
Natural Gas	103.4	130.0	143.8	175.4	194.8	97.2	131.9	154.1	201.8	237.3
	Actual price difference (fuel oil and coal versus natural gas)									
Fuel Oil:										
No. 2	131.7	134.3	128.1	226.7	369.6	129.2	125.4	114.1	201.3	299.9
Low Sulfur No. 6	103.7	99.1	81.3	144.8	258.5	96.4	89.4	62.7	120.6	229.2
High Sulfur No. 6	65.3	69.1	42.9	89.3	166.6	68.7	66.3	32.0	59.7	112.3
All No. 6	92.5	90.4	68.5	124.3	228.7	85.6	78.5	48.6	95.2	180.4
Coal: All Grades	(18.6)	(35.3)	(32.2)	(53.0)	(66.1)	(3)	(3)	(3)	(3)	(3)
	Price difference ratio [4] (fuel oil and coal versus natural gas)—ratio									
Fuel Oil:										
No. 2	1.274	1.033	.891	1.292	1.897	1.329	.951	.740	.998	1.264
Low Sulfur No. 6	1.003	.762	.565	.826	1.327	.992	.678	.407	.598	.966
High Sulfur No. 6	.632	.538	.298	.509	.855	.707	.480	.208	.296	.473
All No. 6	.895	.695	.476	.709	1.174	.881	.595	.315	.472	.760
Coal: All Grades	(.180)	(.272)	(.224)	(.302)	(.339)	(3)	(3)	(3)	(3)	(3)

[1] As reported in DOE/EIA Energy Data Report entitled *Cost and Quality of Fuels for Electric Utility Plants* (Annual summary data 1976–1979) and Monthly Report for January 1980. Note: All prices are delivered prices to steam electric plants. Prices paid for No. 6 fuel oil include prices paid for minor amounts of No. 4 and No. 5 fuel oil, crude and topped crude.

[2] Fuel oil prices are reported on FEA Form P302–M–1, "Petroleum Industry Monthly Report for Product Prices." Natural Gas Prices are those paid by industrial customers of major interstate pipeline companies as reported on FPC Form No. 11, "Natural Gas Pipeline Company Monthly Statement."

[3] The price data for coal is the same as shown under FPC Form No. 423 price data.

[4] Mathematically the price difference ratio is $P_2—P_1/P_1$; Where P_2 = the price of fuel oil or coal and P_1 = the price of natural gas. The ratio indicates the percent difference between natural gas and alternate fuel prices. For example in January 1980 electric utilities reported that in that month they paid 1.897 times more (189.7 percent) for No. 2 fuel oil than they paid for natural gas.

As determined in Docket No. RM79–40 NOPR issued June 3, 1980, corrected for clerical/typographical error.

[¶ 30,182]

45 F. R. 54741 (August 18, 1980)

18 CFR Part 282

[Docket No. RM80-10]

Incremental Pricing; Order Denying Rehearing and Revoking Amendments Made by Order No. 80

Issued: August 1, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Order Denying Rehearing and Revoking Amendments Made by Order No. 80.

SUMMARY: On June 5, 1980, the Consumer Energy Council of America filed a petition for rehearing of Order No. 80, raising a single issue—whether the legislative veto provisions of section 202 of the Natural Gas Policy Act of 1978 (NGPA) are constitutional. In this order denying rehearing, the Commission finds that sound administrative practice requires it to presume the constitutional validity of all provisions of the NGPA. Nevertheless, since the constitutional issue raised here has not yet been spoken to by the Supreme Court, the Commission notes that it is possible that the legislative veto of section 202 could eventually be held to be invalid. In view of this potential, the Commission also acts in this order to revoke the amendments made by Order No. 80, on the basis that the underlying premise of its decision to promulgate the order would no longer apply without the legislative veto mechanism.

EFFECTIVE DATE: August 1, 1980.

FOR FURTHER INFORMATION CONTACT:

Tom S. Runge, Office of the Chairman, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8335.

Stephen Melton, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8467.

In Order No. 80, issued on May 6, 1980, the Commission promulgated a rule in this docket and submitted it to Congress as required by section 202(c) of the Natural Gas Policy Act of 1978 (NGPA). That rule would have expanded the scope of incremental pricing from its present coverage of industrial boiler fuel facilities to include "any industrial facility which is within a category defined by the Commission." The rule proposed to Congress would have extended the incremental pricing program "to all industrial users except those specifically exempted." (Order No. 80 at 6)

In Order No. 80, the Commission did not "second-guess the social and economic judgments that Congress made in enacting Title II." (Order No. 80 at 5) On the contrary, it saw its role as a more limited one, *i.e.*, it brought "its technical expertise to bear on the design of a workable Phase II rule that [could] best advance the purposes set by Congress." (*Id.*) The Commission believed, however, that in the last analysis the Congress had reserved to itself the question "whether this Phase II submittal meets adequately the social and economic goals of the incremental pricing program or, indeed, whether those goals are still appropriate." (*Id.*)

On May 6, 1980, the Commission transmitted the rule to Congress. On May 20, 1980, the House of Representatives passed a Resolution of Disapproval (H. Rep. 655),[1] which under the language of section 202 of the NGPA makes the rule ineffective.

On June 5, 1980, the Consumer Energy Council of America, *et al.* ("CECA"), filed a timely petition for rehearing of Order No. 80. In that petition, CECA raises a single issue—whether the legislative veto provision of section 202 is constitutional.[2] On July 8, 1980, the Commission granted rehearing solely for the purpose of further consideration.

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[1] This is the only instance where Congress has exercised its veto in relation to the incremental pricing progam.

We recognize that the constitutional issue concerning the validity of the legislative veto mechanism is one which has not been decided by the Supreme Court of the United States, and is one on which there is great diversity of view both within the Federal government and among legal scholars. Nevertheless, it was, at the time order 80 was promulgated and today remains, our view that sound administrative practice requires that presumption of constitutional validity of the statutes entrusted to this Commission for implementation.[3]

If section 202(c) of the NGPA containing the Congressional review and legislative veto mechanism is eventually held to be invalid, an argument can be made that Order No. 80 would take effect at the expiration of 90 days after the 30-day Congressional review period. This is CECA's position. In view of this potential (a matter squarely presented to us in this application for rehearing), the Commission has examined the underlying premise of its decision to prescribe Order No. 80 in its present form. As we noted in Order No. 80, many commenters suggested that no section 202 rule, or the narrowest possible section 202 rule, be prescribed. We refused to entertain these arguments, stating:

> The Commission believes that it was neither requested nor authorized to second-guess the social and economic judgments that the Congress made in enacting Title II. The role of the Commission under Section 202 is more limited. Instead, the Commission is instructed to bring its technical expertise to bear on the decision of a workable Phase II rule that can best advance the purposes set by the Congress. It is up to the Congress to decide whether this Phase II submittal meets adequately the social and economic goals of the incremental pricing program or indeed, whether those goals are still appropriate. (Order No. 80, p. 5)

Clearly, if section 202(c)'s Congressional review provisions are constitutionally invalid, then our premise for refusing to consider these arguments, namely that it "is up to Congress to decide whether this Phase II submittal meets adequately the social and economic goals of the incremental pricing program", is equally invalid, and cannot be the basis for such refusal. If the Commission refused to consider material arguments made in the course of the rulemaking because of this faulty premise, then Order No. 80 cannot be the product of reasoned decisionmaking and the Commission is neither authorized nor required to place it in effect. Thus this question seems largely academic at this point, and Order No. 80 cannot take effect under its terms at the conclusion of the 90-day period which follows the conclusion of the 30-day Congressional review period.

As previously pointed out, the Commission has not yet independently evaluated whether the Phase II rule meets the social and economic goals of the Title II incremental pricing program.

But we question whether the marketplace should be left exposed to the potential of significant disruption should the courts not share this view of the law. We think such an exposure to be most inadvisable. Hence, we propose to adopt an administrative course which should remove this jeopardy.

Moreover, if the Commission were to make that independent social and economic evaluation—and we stress that we have not made it previously and do not make it here today—we believe as an initial matter that we might well have very serious reservations as to the wisdom of making the Phase II rule effective. As we pointed out in Order No. 80, there are serious questions of general social and economic policy that deserve to be addressed. For example, we noted in the order that the rule there prescribed did not appear to be capable of carrying out the market ordering function of incremental pricing.[4]

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[2] CECA raises this issue by requesting the Commission to strike the following language from the Order:

". . . if neither House of Congress passes a Resolution of Disapproval of the regulations transmitted to them in this Order within 30 days of Congressional review, as determined in accordance with section 507(b) of the NGPA . . . ." (Order No. 80, p. 93)

Petitioners apparently believe that the elimination of this language could make the rule effective in accordance with its remaining terms.

[3] See *Califano* v. *Sanders*, 430 U.S. 99, 109 (1976); *Ostereich* v. *Selective Board*, 393 U.S. 233, 242, (1968) (Justice Harlin concurring in the result); *Buckeye Industries, Inc.* v. *Secretary of Labor*, 587 F.2d 231 (5th Cir. 1979); and *Speigel, Inc.* v. *Federal Trade Commission*, 540 F.2d 287 (7th Cir. 1976).

Moreover, we note that the rule in its present form [5] might be an imperfect instrument for sheltering high-priority users from the economic impacts of rapidly increasing natural gas prices. Perhaps a better mechanism can be devised but if so, we were not able to discover it in the strict statutory period for implementation of incremental pricing.

In order to fairly make a broader judgment on the social and economic desirability of the rule as a sheltering device, or as a market-ordering device, the Commission would also have to consider and weigh much more imponderable and possibly contervailing factors—for example, the possibility that these fairly minimal savings to millions of high-priority users will be more than offset, in a broad social and political sense, by the significant surcharges and the increased costs of required reporting and accounting measures that would be imposed on the natural gas users subject to the Phase II rule.

A related and equally difficult social policy judgment that should properly be made by the Commission—if the Congress cannot constitutionally make it by way of the section 202(c) legislative veto—is whether the projected savings for high-priority users in annual gas costs might not be largely offset, in a strictly monetary sense, by increased prices for consumer goods possibly caused by passed-on Phase II incremental pricing surcharges.

These imponderables, and the other major social and economic issues raised by Order No. 80, simply must be assessed, and a reasoned judgment reached upon them, before the rule takes effect. The House of Representatives made a judgment to reject this proposal after consideration of these and other social and economic issues. The Commission has not made and does not today attempt an independent evaluation of them.

Moreover, such an evaluation in the future would be aided by an opportunity to judge the implementation of the Phase I over the coming months and the accompanying opportunity to address and resolve any administrative problems that may be encountered.

This seems to us the wiser administrative course of action, one that would minimize the risk of economic dislocations to the industrial sector and avoid adding at this time further recessionary pressures on American industry. It is the administrative course which we would choose, if the choice were ours to make.

In order to assure that an opportunity to evaluate Phase I, and the impacts of Phase II as proposed in the event section 202(c) is held invalid, the Commission will exercise its authority under sections 201 and 202 to amend the rule under section 201 to revoke the amendments made by Order No. 80. Revocation will permit the Commission in the future to carefully weigh these considerations and if appropriate prescribe a Phase II rule which it finds to be in the public interest.

The Commission's authority to amend is clear. Section 201 directs the Commission to prescribe an incremental pricing rule applicable to industrial boiler fuel facilities, and authorizes the Commission "from time to time" to amend the rule. Section 202 requires the Commission to amend the 201 rule to expand its applications to such other categories of industrial facilities as it may define. The amendment required by section 202 to the section 201 rule is part of the section 201 rule. Thus, the amendment may, by the terms of section 201, be amended "from time to time." By the terms of 202(a)(2), the amendment required by section 202 and all amendments "applicable to facilities to which the amendments required by this section applies (other than technical and clerical amendments)" are subject to the Congressional review procedure in section 202(c), if those procedures are constitutionally valid. However, the amendment made by this order will have legal effect only if section 202(c) is invalid. Moreover, if section 202(c) is invalid, then the Congressional review procedure it sets out is inoperative. The amendment shall, in this event, take effect immediately on issuance without submission to either House of Congress.[6]

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[4] Order No. 80, pp. 57–66.

[5] As Order No. 80 pointed out, at p. 71, sheltered high-priority users would, on the average, probably be spared a total of about $.14 per Mcf of purchased gas. For the average household using natural gas for heating or cooking purposes, this translates into a savings of about $18 per year.

The Commission orders: (A) The petition for rehearing is denied.

(B) The amendments made by Order No. 80 (45 FR 31622, May 13, 1980) to the Commission's regulations are revoked, effective on issuance of this order

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,183]

45 F. R. 56034 (August 22, 1980)

18 CFR Parts 271, 273, 274

[Docket No. RM79-76; Order No. 99]

Regulations Covering High-Cost Natural Gas Produced From Tight Formations

August 15, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: Federal Energy Regulatory Commission pursuant to sections 107 (b) and (c) of the NGPA hereby adopts regulations that establish an incentive maximum lawful price ceiling for certain natural gas produced from tight formations. The regulations also provide guidelines for formally designating tight formations and for determining which wells drilled into such formations will qualify for the incentive price.

EFFECTIVE DATE: September 22, 1980.

FOR FURTHER INFORMATION CONTACT:

June G. Perin, Office of the General Counsel, 825 North Capitol Street, NE., Room 8100-D, Washington, D.C. 20426, (202) 357-8473.

Colette Bohatch, Office of the General Counsel, 825 North Capitol Street, NE., Room 8100-B, Washington, D.C. 20426, (202) 357-8140.

Webster Gray, Division of NGPA Compliance, Office of Pipeline and Producer Regulation, 825 North Capitol Street, NE., Room 6000, Washington, D.C. 20426, (202) 357-8682.

SUPPLEMENTARY INFORMATION:

I. Introduction

The Federal Energy Regulatory Commission (Commission) firmly supports the national policy to encourage production of natural gas from unconventional sources that can be put into production only at extraordinary risk or cost. One such source of gas is a fairly common geological feature known as a "tight formation" or "tight sand" that is described in detail below. By the final regulations promulgated in this order the Commission establishes an incentive price ceiling for certain natural gas produced from tight formations.

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[6] It is similarly clear, if section 202(c) is invalid, that there is no requirement that Order No. 80 be made effective at any particular time or at all. Section 202(a)(1) requires the Commission, within 18 months after the enactment of the NGPA, to "prescribe" an amendment to the rule under section 201. However, under section 202(a)(2), the amendment prescribed "shall take effect only as provided in subsection (c) [of section 202]." if section 202(c) is invalid, the statutory mechanism for placing the rule in effect no longer exists, and the Commission is not required to place Order No. 80 in effect.

This rule implements the Congressional authorization to the Commission in section 107(b) of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3317), to set a "special price" which is "necessary to provide reasonable incentives for the production of * * * high-cost natural gas." In exercising this authority, the Commission has been concerned that any section 107 special price provide an incentive during the period before the NGPA deregulation beginning in 1985. The key question addressed by the Commission in this rulemaking is what incentive price best meets the statutory standard of a "necessary" incentive during the transitional period between issuance of this rule and 1985.

In addition to specifying an incentive price, the regulations also provide guidelines for formally designating tight formations and for determining which wells drilled into such formations will qualify for the incentive price. Under the rule, most new wells and recompleted wells producing from designated tight formations will be eligible for the incentive price.

II. Background

A "tight formation" is a sedimentary layer of rock cemented together in a manner that greatly hinders the flow of any gas through the rock.[1] Because such a formation is characterized by low permeability, wells drilled into gas-bearing formations of this kind usually produce at very low rates.

To stimulate production from these formations, producers must use expensive enhanced recovery techniques. The technique usually applied to tight formations involves massive hydraulic fracturing, which creates a system of cracks permitting trapped gas to flow more easily into a wellbore.

It is estimated that between 200 and 700 trillion cubic feet (Tcf) of natural gas is trapped in tight formations within the United States. Depending upon the applicable price incentive, it is estimated that the gas recoverable in tight formation might equal the amount of proven domestic conventional gas reserves.

The estimated amount of tight formation gas includes formations that are presently being developed as well as formations that are known but undeveloped. This rule will provide an incentive price for production of gas produced from several types of drilling programs: (1) Infill wells drilled into certain developed tight formations; (2) recompletion of wells that are already producing from formations vertically situated in relationship to the designated tight formations; and (3) new wells drilled and completed in undeveloped tight formations. Most of the first gas to be produced from tight formations under this incentive program is likely to be gas produced through recompleted wells. Some of these wells can be brought into production without any additional drilling by completing existing wells in tight formations.

The Commission issued a Notice of Inquiry (Docket No. RM79-44, 44 FR 34969, June 18, 1979) regarding high-cost gas. The public response to the notice generally recommended that tight formation gas be considered for qualification as a high-cost gas. President Carter, in his energy address to the nation on July 16, 1979, also urged the Commission to set a price incentive for tight formation gas.

A Notice of Proposed Rulemaking was issued by the Commission on August 29, 1979 (Docket No. RM79-76, 44 FR 52255, September 7, 1979), proposing an incentive price ceiling for tight formation gas. Public hearings were held in Washington, D.C. on September 24th and in Denver, Colorado, on September

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[1] One commenter was concerned that the Commission referred to "tight sands" in the preamble of the inerim rule. Any use or reference "sands" in the interim rule or in this rule does not have the effect of limiting the applicability of the rule to "tight sands." The rule makes the incentive price available for all gas produced from qualifying tight formations.

27th. Numerous written comments were received. The Commission encouraged State agencies that would be affected by these regulations to participate in the rulemaking process.

Interim regulations were developed from the proposed regulations taking into account the suggestions submitted during the public proceedings. The interim regulations were issued on February 20, 1980, along with newly proposed regulations for recompletion tight formation gas. The Commission requested comments on both the interim regulations and the proposed regulations.

The Commission has been persuaded by the final series of comments to adjust upward the incentive price ceiling for new tight formation gas, to incorporate an incentive price ceiling for recompletion tight formation gas, and to refine further the designation and well category determination procedures of the interim rule.

III. Summary of the Rule

A. Price

These regulations establish an incentive price ceiling for new and recompletion tight formation gas produced from designated tight formations (see § 271.703(b) (2) and (3)). The maximum lawful price for both categories is the effective negotiated contract price (see § 271.703(a)) between the buyer and seller or 200 percent of the maximum lawful price for section 103 gas, whichever is lower.

B. Negotiated Contract Price Requirement

The incentive price established in this rule is only a ceiling price. Once gas is found to qualify as new or recompletion tight formation gas, the seller can collect a price higher than the otherwise applicable maximum lawful price up to the ceiling if the contract contains an effective negotiated contract price.

As defined in § 271.702 of this rule an effective negotiated contract price is one that either is established by reference to the incentive pricing authority of the Commission under section 107 of the NGPA or is established by a fixed rate or fixed escalator clause, *i.e.* a clause that changes the price for the gas by a specified amount on a specified date.

C. Designation of Tight Formations

As provided in the interim rule, the price incentives in the final rule are available only for gas produced from tight formations that are designated in accordance with the procedures set forth in the rule. The designation procedure begins with the jurisdictional agency. The jurisdictional agency will establish procedures and conduct investigations to identify tight formations that meet the guidelines set forth in § 271.703(c). The jurisdictional agency will then recommend to the Commission that specific formations or portions thereof be designated as tight formations.

The guidelines for identifying tight formations contain standards regarding permeability, gas productivity, and production of associated oil. In addition, if infill drilling had been approved for the formation prior to the date of recommendation, the guidelines require an exclusion for any portions of the formation for which an incentive price is not warranted.

1. *Permeability Standard.* The Commission has established a permeability limit of 0.1 millidarcy. Pursuant to this limitation the average permeability throughout the "pay" or gas-producing section of the recommended formation may not exceed 0.1 millidarcy. If the formation does not meet the 0.1 millidarcy permeability standard, the jurisdictional agency may still recommend the formation under the alternative guideline contained in § 271.703(c)(2)(ii). Under this guideline, the jurisdictional agency must make an adequate showing that the formation exhibits low permeability characteristics and must find that, due to extraordinary costs, the incentive price is necessary for production.

2. *Gas Productivity Standard.* The guidelines also impose a gas

productivity standard. According to this standard production expected from the recommended formation, without stimulation, may not exceed a certain rate. The standard applicable to a given formation depends upon the average depth from the surface location to the top of the formation. The cost of drilling and completing gas wells increases exponentially with the depth of the well, so deeper wells must produce more to be economical. We have provided this productivity scale to allow a greater production rate for the deeper, more expensive wells.

3. *Associated Oil Productivity Standard.* A well in a designated tight formation may not be expected to produce more than five barrels of crude oil per day. The definition of crude oil includes only hydrocarbons that exist in the liquid phase in underground reservoirs and remain liquid at atmospheric pressure after passing through surface separating facilities. The five-barrel limit has been imposed because the value of oil in greater quantities should, by itself, provide the necessary incentive for the development of the formation, obviating the need for additional incentives.

4. *Infill Drilling Standard.* A guideline has been added in § 271.703(c)(2)(i)(D) concerning infill drilling that was authorized prior to the date of recommendation. Under this guideline the jurisdictional agency should exclude that portion of the formation it determines can be developed without the incentive price.

D. Recommendation and Designation of Tight Formations

Section 271.703(c)(3) of the rule also provides that a jurisdictional agency's recommendation must be accompanied by engineering, geological, geographic, and other information identifying the characteristics of the formation. Upon receipt of a recommendation the Commission will publish it in the Federal Register, will accept written comments on the recommendation, and will provide an opportunity for public hearing. After the comments have been reviewed, the Commission will prescribe a rule approving, disapproving, or modifying the recommendation. No modification will be made until the jurisdictional agency has been consulted. If the formation is approved, the Commission will list the qualifying formation in new § 271.703(d) of the regulations.

E. Well Determinations

Once a recommended formation has been approved by the Commission, a well category determination can be made regarding the eligibility of the gas as either new tight formation gas or recompletion tight formation gas. To qualify for one of these categories, the gas must meet the definitional criteria set forth in the definitions of new or recompletion tight formation gas in § 271.703(b) (2) and (3), respectively.

Section 274.205 of the rule also provides two sets of filing requirements for well determinations: one for new tight formation gas and the other for recompletion tight formation gas. In the case of new gas, the requirements are designed to elicit the following information: first, whether such gas has been produced from a designated tight formation; second, whether the surface drilling of the well was begun on or after July 16, 1979; and third, whether the gas qualifies as new natural gas or is produced through a new onshore production well. In the case of recompletion gas, the application must show that the gas is produced from a designated tight formation through a well which was not completed for production from the designated tight formation before July 16, 1979.

IV. Comment Analysis

A. Price

Under § 271.702 of the interim rule, an incentive price ceiling of 150 percent of the section 103 price was available for "new tight formation gas," defined in § 271.703 as gas: (1) Which is new natural gas, or gas produced through a new onshore production well;

(2) Which is produced from a designated tight formation through a

well the surface drilling of which began on or after July 16, 1979; and

(3) For the first sale of which a negotiated contract price is effective.

At the time the interim rule issued, the Commission proposed the following definition for tight formation gas produced through recompleted wells: (c) "Recompletion tight formation gas" is natural gas: (1) Which is produced from a designated tight formation through a well, the surface drilling of which was begun before July 16, 1979, if such well was not completed for production from such formation before July 16, 1979; and

(2) For the first sale of which a negotiated contract price is effective.

and proposed a maximum price as follows: (2) *Recompletion tight formation gas.* The maximum lawful price, per MMBtu, for recompletion tight formation gas shall be the lesser of: (i) The negotiated contract price; or

(ii) The maximum lawful price specified for the Subpart C of Part 271 in Table I of § 271.101(a) [section 103].

In this final rule, the Commission has increased the interim ceiling price for new tight formation gas and has also made the incentive price applicable to recompletion tight formation gas. Modifications to the above-quoted definitions were made and are described in a separate discussion below.

The ceiling price for new tight formation gas provided in the interim rule was considered by the Commission to be a substantial incentive at 150 percent of the section 103 price.[2] However, the Commission was open to suggestions recommending a higher incentive price but requested that such recommendations be supported by data.

The Commission's reluctance to adopt a higher price also reflected a concern that a higher price might create perverse incentives, that is, manpower and material resources would be shifted from the production of other types of gas to less productive but higher priced tight formation gas with the consequence being a decrease in the nation's total production of natural gas. Because the interim record was punctuated with legal and practical questions, the Commission set a moderate interim price and invited further comment and submission of information on the need for a higher price.

The next round of comments submitted in response to the interim rule presented for the most part conclusions unsubstantiated with data or empirical information, even though the Commission strongly urged that such supporting information be submitted on the price issue. The Commission particularly requested that additional information be submitted to enable it to make the requisite statutory findings that a higher incentive price is "necessary to provide reasonable incentives." Despite this appeal, most of the commenters asserted without substantiating information that a higher price is necessary and that the price should be indexed to a commodity value of gas.

Commenters can be divided into three groups. Some suggested a commodity value based upon the marginal value of gas supplies such as imported gas. Others suggested a Btu-equivalent price based upon oil products with which gas would compete. The third but smaller group of commenters supported prices in line with the interim price.

Comments filed on behalf of several members of the U.S. Senate, producers, and governmental agencies supported a Btu-equivalent price for new tight formation gas. Some suggested using decontrolled domestic oil, while others suggested imported oil. Utilizing an oil price as an index would probably require a ceiling price around 250 percent of the section 103 price as of August, 1980.

Others suggested pricing new tight formation gas at the border price of imported Mexican or Canadian gas, which is approximately 200 percent of the section 103 price as of August, 1980.

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[2] Regarding incentive prices, the Conference Report stated that the price need not be cost-justified. H. Rep. No. 95–1752, 95th Cong., 2d Sess., 88 (1978).

Numerous arguments were offered in support of the higher incentive price. Several commenters argued that production costs for gas from tight formations are approximately twice as high as production costs from conventional formations. The greater cost of tight formation production, they contended, is attributable to the massive hydraulic fracturing that is required to enable gas to flow at a producible rate to a wellbore.

Commenters stated that gas production from tight formations is also accompanied by a slow rate of production that extends the payback period to approximately twice what would be expected for a conventional well. The commenters contended that together, the increased costs and the extended payback period require the price of tight formation gas to be approximately four times greater than the price for conventional gas in order to provide an incentive for the development and production of tight formation gas.

A commodity price was further supported by the commenters' argument that tight formation reserves can be added to the nation's total gas reserve potential only if investment dollars are attracted to tight formation development. If the incentive price is high enough, investment dollars will be attracted to the development of tight formation gas reserves. The anticipated return on capital investment in a tight formation will be compared, however, to other investment opportunities. The commenters argued that energy investment dollars will not flow to tight formation development if the price for such gas is not, at least, comparable to the free market value of the gas.

Commenters argued that the statute permits a commodity value price if that price is necessary to provide reasonable incentives for production of high-cost gas. They also emphasize that the Conference Report suggests that the price need not be cost-based or require cost justification.[3] They argued that a cost comparison between tight formation drilling and conventional drilling indicates that tight formation gas must be priced at least twice as high as conventional gas to provide an incentive that exceeds the cost basis. It is asserted by these commenters that the Commission is free to boost the incentive to reflect a commodity value price for this gas if the Commission finds that the price will provide reasonable incentives.

Several Senators further argued that this statutory interpretation is supported by the legislative history. The House Ad Hoc Committee of Energy stated that the incentive price is extended to provide the "fullest practicable development" of our gas reserves.[4] This can be accomplished by extending a commodity value price so as to make development of tight formations competitive with other energy sources. In this way, tight formations can successfully compete with other energy sources for investment dollars.

The interim price was supported by Northwest Pipeline, the Public Service Commission of New York, and Southern California Gas Company. Texas Oil and Gas Company suggested a variation of the interim price, *i.e.* 150 percent of the otherwise applicable maximum lawful price, either the section 103 or 102 price. Professor Dorfman from the University of Texas and the Interstate Oil Compact Commission suggested a graduated price based on the depth of a well. Under this last approach a shallow well would qualify for a price approximately at the interim price but a deep well would qualify for a higher price approaching the Btu-equivalent price of oil.

Some commenters maintained that a higher price would result in a windfall to producers and not necessarily result in increased production from tight formations. They shared the concern about perverse incentives expressed by the Commission in the interim rule, that even if increased production from tight formations occurred, drilling rigs would be diverted from conventional wells to tight formations. They argued that because the drilling rig industry would be unable to meet the increase in the total demand for new rigs there would be less activity in other, more productive formations. Their conclusion was that the nation's total gas production would decline because of the shift of investment dollars and drilling activity from conventional sources to tight formations that have lower rates of productivity.

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[3] H. Rep. No. 95-1952, 95th Cong. 2d Sess., 88 (1978).

[4] H. Rep. No. 95-543 (Vol. I), 95 Cong., 1st Sess. 46 (1977).

Commenters further argued that actual delivery of gas produced from tight formations would be deferred because of a lack of pipeline capacity to handle increased production from many tight formations.

On statutory grounds, these commenters argued that price treatment under section 107 does not warrant a Btu-equivalent or a commodity-value price. Indexing the price of tight formation gas to a commodity value effectively deregulates the price because the suggested commodities, imported oil, domestic decontrolled oil, and imported Canadian or Mexican gas, are free of price controls.

In support of this argument, the commenters stated that Congress' explicit deregulation of certain categories of gas, including for example high-cost gas, section 107(c) (1) through (4), did not mean that other categories can or should be deregulated. Although the Commission was given discretion over determination of additional categories of high-cost gas under section 107(c)(5) and establishment of a ceiling price for these additional categories under section 107(b), they contended that the Commission does not have the authority to deregulate the price of such gas.

After these comments were received, the Commission held a hearing on June 10, 1980, to discuss the commenters' suggestions regarding the interim rule. This meeting provided an opportunity for a frank exchange between interested parties and the Commission regarding, among other issues, the price issue. Since the majority of participants at this hearing urged a price higher than the interim price, the discussion centered around the economic basis for a higher price and the policy that would be furthered by a higher price.

V. Price Analysis

The Commission is in a unique position in implementing section 107. Congress established a pricing scheme in Title I of the NGPA and mandated prices which it believed provided appropriate incentives for all categories of gas, except for categories of high-cost gas under section 107(c)(5). Thus, in sharp contrast to other categories of gas under the NGPA, Congress left unanswered the question of what incentive price should be set for high-cost gas and granted to the Commission the discretionary authority to establish the appropriate incentive price.

In establishing prices for high-cost gas, the Commission must be sensitive not to undermine Congress' overall pricing scheme. Section 107(c)(5) prices must not create perverse incentives but must be in harmony with the overall Congressional scheme.

In addition, the Commission must balance the competing interests of suppliers and consumers. On the supply side, gas producers must make long term resource commitments for the development of tight formations. It is in the nation's interest that they view development of tight formation gas as an attractive investment. The higher the incentive price, the more attractive it will be to develop this resource. The price should provide an incentive for producers to begin such development now. Absent this additional incentive, some producers may decide to defer production efforts until decontrol, which begins in 1985. On the other hand, consumers should not be required to pay a price higher than the otherwise applicable NGPA price unless there is a reasonable basis for assuming that a higher price is necessary and will result in an increased supply of gas.

Keeping in mind the needs of producers and consumers, the focus of our pricing inquiry is to determine the necessary incentive for the transition period between now and 1985. It is our intention to establish a price that will stimulate production of gas from tight formations during the transition period.

The Commission has developed and applied two different approaches in determining the necessary and appropriate incentive price for this transition period. One approach is value-related, while the other is cost-related. The value-related approach attempts to index the price of tight formation gas to that of other energy forms. The cost-related approach looks instead to the costs and risks associated with tight formation gas production. Taken together, the two approaches define a range of reasonableness for the incentive price which would seem to be fully consistent with the statutory mandate.

A. Value-Related Price Approach

Congress, in enacting the NGPA, stated that natural gas prices should no longer be set on a utility-type, cost-based approach as had been the practice under the Natural Gas Act (NGA). In connection with this change from cost-based prices to incentive prices, Congress realized that the NGA prices discouraged producers from producing expensive, unconventional resources. The incentive prices established by Congress are not based upon a strict commodity-value concept because the NGPA price ceilings do not explicitly track any alternative fuel price. But it seems that the Congress intended a pricing scheme that related incentive prices to the price of competing fuels rather than just to the cost of producing gas.

Many commenters who urged a commodity-value approach for tight formation gas would have the Commission adopt an incentive price tied explicitly to the price of some other fuel. The fuels most commonly suggested were crude oil and fuel oil. These commenters concluded, on the basis of current prices, that the price for tight formation gas should be $6.00 or more.

The commodity value of gas is tied to end-user costs of competing or alternative fuels. The value of each additional unit of gas to the end user will depend upon the alternative fuel capability of that user. Over the near term (0–5 years), additional or "marginal" gas supplies will tend to be used in industrial or electric utility applications. For these uses, the principal competing fuel will be No. 6 (residual) or No. 2 (distillate) fuel oil. Few, if any, of these applications can be served by burning unrefined crude oil. So the appropriate basis for measuring the end-use market value of tight formation gas is fuel oil. Therefore, the Commission believes that a properly designed commodity-value approach must utilize fuel oil rather than crude oil as the point of reference.

The appropriate maximum lawful first sale (wellhead) price of tight formation gas can be derived using this approach by subtracting from the end-use market value of fuel oil the average cost of moving gas from wellhead to industrial and utility customers. It should be apparent that the comments of those who recommended a wellhead price for tight formation gas based on Btu equivalence with imported crude oil do not present a logically consistent model.

The Commission cannot adopt the suggestion to derive the first sale price ceiling of tight formation gas by reference to the price of imported fuel oil. There can be no assurance that these two prices would result in comparable values at the point of end use, which is the best transactional point for measuring value of fuel because no further value is added to the fuel when it is burned.

Having established that the preferred method of implementing a commodity-value approach is by reference to the price of fuel oil, the Commission must next decide which grade of fuel oil is most appropriate. Because the Commission seeks to establish a favorable incentive for tight formation gas, it has chosen to use No. 2 fuel oil, which is generally the more expensive.

The most recently available Btu-equivalent price based on the delivered price for No. 2 fuel oil to electric utility facilities was $5.78[5] effective April, 1980 as reported by the Energy Information Agency (EIA).[6] Prices of No. 6 residual fuel oil were lower by $2.00 or more.

Using this Btu-equivalent delivered price, the imputed value of tight formation gas at the wellhead can be obtained by subtracting the average cost of transporting gas from the wellhead to the user. Transportation costs will vary depending primarily upon the distance of the industrial or utility user from the tight formation source. However, referring to the EIA's *Monthly Energy Review* for March, 1980, the average transportation and distribution costs for gas appear to be roughly $1.00 for industrial and utility customers. Reducing the Btu-equivalent delivered price, $5.78, by this $1.00 average transportation cost results in a "net back" wellhead value of equal to $4.78 for marginal supplies of gas. As measured by this method, we believe a price of around $4.78 reflects the upper bound on the wellhead value of gas to the economy for additional domestic production as defined by the commodity-value or the Btu-equivalent approach using No. 2 fuel oil as an index.[7] This price is sharply lower than the $6.00 price advocated by proponents of a simple imported crude oil equivalent price for tight formation gas.

Another commodity-value approach that the Commission considers to be of merit would relate the maximum lawful price for tight formation gas to the price of imported gas rather than to fuel oil. At present, the border price for Canadian and Mexican gas is $4.47.

B. Cost-Related Approaches

A "necessary" price within the meaning of the statute must at a minimum cover reasonable production costs and provide a reasonable profit. While the Commission need not establish a cost-justified price, estimates regarding the costs of production do provide one vital source of information for judging the adequacy of an incentive price. The Commission has considered two cost-related approaches, a supply-response approach, and a relative-costs approach that compares costs of tight formation production to the costs of other NGPA production.

1. *Supply-Response Approach.* At the time this rulemaking was initiated, the National Petroleum Council (NPC) had begun an extensive study of the resource base and production potential of domestic gas reserves in undeveloped tight formations.[8] The Commission has analyzed the NPC data to estimate

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[5] In quoting prices throughout the discussion of the price analysis, the Commission eliminated in most instances references to unit measures, of Mcf (thousand cubit feet) and MMBtu (million British thermal units). For the purpose of this discussion, the terms are interchangeable because an average Mcf contains approximately one MMBtu.

[6] The Energy Information Agency publishes monthly a report entitled Energy Data Report, FPC Form No. 423.

[7] The extensive record on incremental pricing developed in connection with the Commission's Title II implementation activities forcefully suggests that high sulfur residual fuel oil should be used to define a commodity value. However, because the Btu-equivalent price for No. 6 oil is now in the range of $2.50 to $3.75 even before subtracting $1.00 of transportation charges, the Commission is of the opinion that despite the logic and strong record linking the gas produced from tight formations to residual fuel oil, indexing the prices for tight formation gas to this fuel would not provide adequate incentive.

[8] The National Petroleum Council is a Federal advisory committee to the Secretary of Energy. The sole purpose of the NPC is to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary relating to petroleum or the petroleum industry. The Commission encouraged its staff to contact the NPC regarding an exchange of information which the NPC has collected on this topic.

potential supply responses to price increases.[9]

The available NPC data indicate that prices higher than the otherwise applicable maximum lawful prices under sections 102 or 103 of the NGPA will produce increases in supply. A significant supply response occurs in the $3.50–$4.00 price range. Beyond this range, however, additional increases in price produced smaller increases in supply. Analysis of the NPC data also indicates that beyond the $3.50–$4.00 price range, the effective cost of the additional supply response may be as high at $7.54. Therefore, the NPC data would support a price of $4.00 on the basis of economically efficient increases in supply.[10]

2. *Relative-Incentive Approach.* A second cost-related approach would relate the ceiling price for tight formation gas to the prices Congress established in the NGPA to provide incentives for developing conventional gas. The measure of a necessary price for high-cost gas under this approach would be derived from consideration of the relative cost, yield, and risk of production from tight formations as compared with conventional gas production.

Relative Cost. Several commenters argued without providing substantiating data that the average total cost of drilling and completing a tight formation well is roughly twice as great as the cost of bringing a comparably deep conventional well into production. This is because the cost of fracturing can be as great as the cost of drilling a well. All other things being equal, this means that a producer will require an incentive price at least twice as high for tight formation production as for conventional production in order for the expected financial return from the two production categories to be equal.

Clearly, this two-fold ratio will not hold for every tight formation well. Some production has a sufficiently low relative cost that it enjoys a positive incentive relative to current conventional development opportunities even at existing NGPA prices. But, on the average, if the relative cost of tight formation drilling is higher, then logic implies that such gas should be afforded a relatively high incentive price for production from this source to be a comparably attractive investment.

Relative Yields. A second prong of this approach is to examine the relative yields of tight formation wells compared to conventional wells. This is more difficult to analyze because upon fracturing, the production rate of a tight formation well may be comparable to or even exceed production from a conventional well during its first year or two. After that point in time, however, production usually falls off dramatically and continues at a relatively low rate for 15 to 20 years or more. In contrast, production rates of conventional wells tend to be relatively high for a period typically between 5 to 7 years, but then drop off dramatically. In that 5 to 7 year period a conventional well typically will have produced as much gas as the tight formation well will produce over its 15 to 20 year life.

Commenters argued that the discounted present value of the revenues expected from tight formation wells tends to be much lower than the discounted present value of the revenues expected from wells drilled in conventional formations. However, it is difficult to define and to quantify "typical" production profiles for tight formation wells and conventional wells, making it impossible to consider lower yields, by themselves, a basis for a higher tight formation gas incentive price.

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[9] A subsidiary problem is to estimate the time pattern of response. To know that eventually the response to a price of X dollars will be Y Tcf's is of only limited assistance if the price of X dollars will be in effect for only a few years and then a different and deregulated price will apply.

[10] Commission staff noted that the NPC estimates were based on certain assumptions regarding the availability of capital, manpower, equipment, and pipeline capacity. Staff believes that the NPC assumptions were somewhat optimistic and that these factors will actually restrain the supply-response. However, staff was not able to quantify the effect these factors would have on the supply response and therefore did not account for them in their supply-response analysis.

Relative Risks. The third step in determining a price using the relative incentive approach is to examine relative risks of production. Section 107(c)(5) refers to production "under such conditions as the Commission determines to present extraordinary *risks* or costs" (emphasis added). The record identifies two types of risks involved in tight formation gas production. One is the normal drilling risk of failing to find a gas bearing formation. The second risk especially pertinent to tight formation development is that of a partially or totally unsuccessful fracturing job. This second element of risk exposure provides a basis for arguing that tight formation production is more risky than conventional gas production. Neither the record nor staff's analysis has yielded an acceptable quantitative estimate of the extent to which the risk exposure of tight formation drilling exceeds conventional activities.

In summary, a "necessary" price can be viewed as the price necessary to create an equal or positive relative incentive as compared with the NGPA incentive for typical conventional drilling. Other NGPA categories, especially sections 102 and 103, provide a new incentive environment to producers. The premise underlying the relative incentive approach is that the price under section 107(c)(5) must be necessary to create a "reasonable" incentive in comparison with other NGPA categories. The record indicates that the Commission can reasonably determine that the combined factors of risk, cost, and yield warrant a relative incentive price for tight formation gas that is at least twice as high as would otherwise be available under Title I (generally the NGPA section 103 or 102 price). This two-fold ratio would indicate a current price of about $4.50 in the case of section 103 (development) wells and about $5.00 in the case of section 102 (new gas).

C. Conclusion—Price Issue

Applied collectively to the information gathered on the record in this proceeding, the value-related and cost-related approaches yield a $3.50–$5.00 zone of prices that can be considered reasonably necessary to create an incentive for tight formation gas production.

As a basis for narrowing this range, the Commission acknowledges that the cost of producing tight formation gas will vary considerably among formations and among specific drilling projects. Virtually any incentive ceiling price that the Commission establishes for tight formation gas will provide a more than ample return on some wells and an insufficient return on other wells. Indeed, the same can be said of the present NGPA ceiling prices for which new tight formation production would otherwise qualify. If the Commission chooses the low end of the $3.50 to $5.00 range, its action would tend to minimize any unnecessary windfalls associated with this rulemaking. On the other hand, a low price will operate to discourage producers from drilling more difficult formations and could retard the development of costly, but promising, fracturing and recovery techniques.

The Commission seeks to resolve this difficult issue in favor of providing as great a production incentive as can be supported by both cost-related and commodity-value concepts. From the standpoint of energy policy, economic policy, and environmental policy, enhanced production of natural gas is in the nation's interest. On the basis of these policy considerations, the Commission rejects the low end of the $3.50 to $5.00 range because it seeks to create a truly favorable drilling environment for tight formation producers.

On the other hand, the Commission rejects the high end of the price range (above $4.78) on the ground that such prices are not supported by assessments of the commodity value of marginal gas supplies. In seeking to provide a high price, but one capable of being supported by both commodity-related and cost-related concepts, the Commission is drawn to the $4.50 to $4.78 range.

A final policy consideration for selecting a specific ceiling price for tight formation gas focuses on the price of imported natural gas, the fuel most likely to be directly displaced by increased tight formation production. On policy grounds, a strong argument can be made that domestic producers of high-cost gas should be permitted to receive at least the $4.47 border price paid by U.S. pipelines for imported gas.

The Commission hereby adopts a price ceiling for tight formation gas at 200 percent of the NGPA section 103 price. For the month of August, 1980, the maximum price is $4.548. Future tight formation gas prices will escalate each month as the section 103 price escalates. For September and October, 1980, the maximum price of tight formation gas will be $4.586 and $4.624, respectively. Maximum prices for subsequent months will be included in the Commission's quarterly ceiling price publications.

A final point of emphasis on the issue of prices for tight formation gas is that the Commission by this rule is establishing ceiling prices only. A producer of tight formation gas does not have authority to charge these ceiling prices unless the producer has the requisite contractual authority. If the contract entered by the producer and the purchaser includes a negotiated contract price as described in this rule, the producer can collect the contract price even if it exceeds the otherwise applicable NGPA price, but the producer cannot collect a price which exceeds the ceiling price established by this rule. The concept of negotiated contract price is discussed more extensively below.

D. Recompletion Tight Formation Gas

At the time the interim rule was issued, the Commission proposed establishing an incentive price for gas produced from existing wells which were not completed for production in a designated tight formation before July 16, 1979. The proposed incentive price for such gas was the section 103 price.

Most commenters agreed that gas produced from recompleted wells should qualify for an incentive on par with the price afforded new tight formation gas. The commenters generally justified their recommendation on the basis that costs of producing from a recompleted well are comparable to costs of producing from a new well (even though drilling costs are lower or are not incurred at all) because a producer would still incur the completion costs that represent a significant portion of the cost of production from a tight formation.

Another factor that argues in favor of an increased incentive price is that recompletion gas is the most readily accessible tight formation gas. The Commission's goal is to encourage producers to employ the most cost efficient and least time consuming programs for recovering tight formation gas. A price discrepancy between new gas and recompletion gas may cause producers to embark upon new well drilling programs with a lag time up to 3 years from inception to delivery in order to receive the higher incentive price for new gas rather than institute more cost-efficient recompletion programs.

To encourage producers to bring tight formation gas into production as soon as possible, the Commission is, therefore, establishing the same incentive price for both categories of gas. The maximum lawful price for recompletion tight formation gas under the final rule is 200 percent of the section 103 price.

E. Other Considerations

The price set in the interim rule at 150 percent of the section 103 price was significantly grounded on a concern that a higher price would create perverse incentives that could result in less, rather than more gas supply on a national basis. A key concern was the predicted inability of the drilling rig industry to meet the increased demand for rigs to drill in tight formations while meeting the demand for rigs for other conventional formations. The NPC study has concluded and has convinced the Commission that the drilling rig industry has the capability to respond to likely

increased demand that may result from this rule. If recompletion tight formation gas is the first to be placed into production, we believe this rule, in the short run, will place a smaller demand on the drilling rig industry than originally predicted.

Similarly, we find the arguments that have been raised regarding the adequacy of currently available pipeline capacity near tight formations to be a minor matter. Customarily, arrangements regarding transportation are made in advance of gas production. In the case of tight formation development, such large capital investments must be committed that it is reasonable to assume that a producer will negotiate with a pipeline for capacity long before the gas begins to flow. We believe that pipelines will make every effort to provide transportation capacity to satisfy the needs of the production industry.

A third concern, not ascribed to by many commenters, is the potential inadequacy of capital to invest in tight formation development. We cannot predict how much capital will be available in the future for tight formation development. It is reasonable however to expect that a good investment will attract capital regardless of the economic environment. If tight formation gas is priced appropriately high, such development will successfully compete for investment capital.

F. Negotiated Contract Price

The negotiated contract price requirement appeared in the interim rule definition of "new tight formation gas" and the proposed definition of "recompletion tight formation gas." The negotiated contract price requirement was also reflected in the maximum lawful prices for new and recompletion tight formation gas.

The interim definitions of "negotiated contract price" and "fixed rate or fixed escalator clause" have been adopted in the final rule. Thus, as defined in § 271.702(a)(1) the term "negotiated contract price" means any price established by a contract which either references the incentive pricing authority of the Commission under section 107 of the NGPA or contains a fixed rate or fixed escalator clause. Fixed rate or fixed escalator clause defined in § 271.702(a)(2) means a provision in a contract for the first sale of natural gas which changes the price for gas by a specified amount on a specified date.

In the interim rule, the Commission stated that negotiated contract requirement was added to insure that the incentive maximum lawful price is extended as an *incentive* for the production of additional new tight formation gas, rather than as a windfall to the sellers. The same rationale would apply to recompleted tight formation gas. The Commission noted that contracts which do not presently contain a negotiated contract price may be amended to permit collection of the incentive price. In addition the Commission clarified that the negotiated contract price requirement in no way constitutes an interpretation of an area rate clause.

The overwhelming majority of comments opposed the negotiated contract requirement on legal and policy grounds and urged that it be deleted. Many comments stated that the Commission is without authority under the NGPA or NGA to require that specific contract language be employed as a condition precedent to collecting the maximum lawful price. The comments asserted that the statutory scheme of the NGPA and the NGA in view of the *Mobile Sierra* [11] line of cases grants parties to gas sales contracts an absolute right to pay or to collect any price they may agree upon, subject only to price ceilings lawfully imposed by a governmental authority. In particular,

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[11] ***United Gas Pipeline Company v. Mobile Gas Service Corporation*, 350 U.S. 332 (1956); *FPC v. Sierra-Pacific Power Company*, 350 U.S. 348 (1956).**

paragraphs 101(b) (5) and (9) of the NGPA permit parties to sell gas at the applicable highest maximum lawful price not in excess of the contract price. It is argued that the Commission lacks authority to impose a requirement that contracts be renegotiated before the maximum lawful price can be collected.

Certain commenters asserted that contracts entered into post-NGPA, specifically reference the NGPA in order to permit the collection of higher prices and that the requirement to specifically reference section 107 could not possibly have been foreseen. Therefore, it is claimed that the rule operates unfairly to preclude sellers, who renegotiated their contracts in comtemplation of NGPA prices and who undertook development of tight formations in anticipation of the Commission's action, from collecting the incentive price.

Under section 107, it is contended that the Commission's authority goes to establishing tight formation gas as high-cost natural gas and establishing an incentive price for its development and production. While it is agreed that the Commission has the discretion to establish the parameters for classification, it is submitted that the Commission does not have the authority to condition a well determination upon the presence of specific contract language. Rather, it is claimed that the NGPA provides that once an incentive price is established the producer must have contractual authority to collect the price (a contract that references the NGPA established price is sufficient to permit collection of the incentive price).

In addition, it is submitted that if the Commission's purpose in issuing this rule is to encourage the development and production of tight formation gas the negotiated contract requirement will not advance this purpose.

Still other commenters submitted that market forces will operate to set prices at an appropriate level only for those tight formations yet to be developed. It is asserted that most tight formations are already identified and are located near conventional gas which is already being produced or is dedicated to pipelines. For these reasons, it is argued that the negotiated contract requirement will place pipelines in superior bargaining positions and they will either refuse to renegotiate contracts up to the incentive price or will require additional consideration. In both cases the requirement will operate as a disincentive to production.

This argument led some commenters to request that purchasers be precluded from demanding additional consideration for existing contracts. If a purchaser refuses to amend his contract he should be required to release the seller from existing contractual obligations. It is also proposed that the Commission should permit producers to file petitions for exceptional relief in circumstances in which the pipeline is being arbitrary and capricious in not offering the required amendment, and in which the producer petitioner can demonstrate that the full incentive price is necessary for further development and production of tight formation gas.

The Commission reaffirms the position taken in the interim rule that it must limit the availability of the incentive price ceiling to those contracts which specifically refer to it (or to the extent permitted under a fixed rate or fixed escalator clause) because its pricing authority is limited to setting incentive prices "necessary" to encourage additional production. Therefore, the negotiated contract price requirement has been retained in § 271.703(a) of the final rule which sets forth the maximum lawful price for both categories of tight formation gas. However, the Commission agrees that an effective negotiated contract price is not a necessary incident to obtaining a well determination and has deleted the requirement from the definitions of new and recompletion tight formation gas.

The Commission believes that the price ceiling if applied to all tight formation gas may operate as a windfall to sellers rather than an incentive to increase production of tight formation gas. This occurs in any case in which one incentive price is established to cover a broad range of production costs and risks. This is especially true where both parties to the contract did not contemplate the availability of an incentive price. The Commission believes that the imposition of the negotiated contract price requirement is therefore necessary to insure that a purchaser is given an opportunity to bargain for increased production of tight formation gas before he agrees to pay a price higher than the otherwise applicable maximum lawful price. In this regard, the negotiated contract price requirement will operate as part of the ceiling price which the Commission is establishing under section 107(b). Thus, in the Commission's view a "necessary" price for tight formation gas is one that is contractually agreed upon either at or below the ceiling price.

The statutory scheme of the NGPA or the NGA and the *Mobile-Sierra* line of cases do not compel a different conclusion. As we stated in the interim rule, parties to gas sales contracts are free to enter into or amend their contracts to permit the collection of the incentive maximum lawful price. Existing contracts that specifically reference the Commission's incentive pricing authority under section 107 of the NGPA or that contain fixed rate or fixed escalator clauses are sufficient to permit collection of any price up to the ceiling price of 200 percent of the 103 price.

VI. Definitions for New and Recompletion Tight Formation Gas

Under § 271.703(b)(1) of the interim rule, gas qualifies as

> new tight formation gas" is natural gas: (1) Which is either new natural gas or gas produced through a new onshore production well; (2) which is produced from a designated tight formation through a well the surface drilling of which began on or after July 16, 1979; and (3) for the first sale of which a negotiated contract price is effective.

In addition, the Commission requested comments on the proposed definition of "recompletion tight formation gas." Under this proposal, gas qualifies as

> recompletion tight formation gas" is natural gas: (1) Which is produced from a designated tight formation through a well the surface drilling of which was begun on or before July 16, 1979, if such well was not completed for production from such formation before July 16, 1979; and (2) for the first sale of which a negotiated contract price is effective.

A. *Negotiated Contract Price*

As stated in the previous section, the negotiated contract price requirement has been deleted from the definitions of new and recompletion tight formation gas, but has been retained in § 271.703 that establishes the maximum lawful price.

B. Spud Date

Only a few comments discussed the requirement that to qualify as new tight formation gas, the gas had to be produced from a well the surface drilling of which began on or after July 16, 1979. One comment suggested that the spud date should be changed to "the date before which a well was not being commercially produced."

Another commenter suggested that February 19, 1977, be adopted as the spud date, for both categories of gas, since it is the pivotal date in the wellhead pricing scheme under the NGPA. This commenter argued that producers who commenced drilling into tight formations prior to July 16, 1979, did so with the expectation that the Commission adopt the suggestion in the Conference Report that gas produced from tight formations should be eligible for incentive price treatment.

Comments of a similar nature were made prior to the adoption of the interim rule. The first suggestion that the cut-off date apply to the date on which gas was first commercially produced from the well has been at least partially accommodated since the incentive price is now available for recompletion gas. In effect, so long as the well was not completed for production in the tight formation prior to July 16, 1979, the gas may qualify for the incentive price. The date of July 16, 1979, (as a spud date) was chosen in the interim rule in recognition of the fact that this rule was undertaken to give effect to a policy initiated by the President's July 16, 1979, speech. This date then, is consistent with the Conference Report, at page 88, which indicates that the pivotal date for section 107(c)(5) gas is the date the Commission exercises its authority under section 107(c)(5). The Commission is not free to make available special prices for gas whose development was encouraged by previously available prices. Therefore, July 16, 1979, will remain as a spud date for new tight formation gas, and as a completion date, for recompletion tight formation gas.

C. Conclusion

The definitions of new and recompletion tight formation gas appear in § 271.703(b) (2) and (3) of the rule. Gas qualifies as new tight formation gas if it is produced from a designated tight formation through a well which was spudded on or after July 16, 1979, and it is either new natural gas (as defined in section 102(c) or (d) of the NGPA), or gas produced through a new onshore production well, (as defined in section 103(c)). To qualify as recompletion tight formation gas, the natural gas must be produced from a designated tight formation through a well which was spudded before July 16, 1979, but not completed for production from such formation before July 16, 1979.

VII. Procedure for Designating Tight Formations

The procedure for designating tight formations was contained in § 271.705 of the interim rule. That section set forth guidelines for identifying tight formations and established procedures whereby a jurisdictional agency may recommend the designation of a tight formation. Upon the receipt of a jurisdictional agency recommendation, the Commission will publish it in the Federal Register and will accept comments on the recommendation. After a review of the comments the Commission will prescribe a rule approving or disapproving the designation of the recommended tight formation.

Several comments and proposals concerning the designation procedure in general were received. Some commenters urged the Commission to "predesignate" or at a minimum to take the lead in designating formations that have been studied by the Department of Energy (DOE) and the United States Geological Survey (USGS). Another suggestion was that there be automatic approval of jurisdictional agency or the USGS recommendations that meet the permeability, gas productivity, and crude oil production guidelines, reserving for Commission action recommendations made under the alternate permeability guidelines. Other commenters stated that the jurisdictional agency process combined with the Commission process will be lengthy, unnecessarily burdensome and will cause a substantial delay in the production of gas from tight formations. These commenters suggest that the time periods and standard of review set forth in section 503 (a) and (b) be utilized.

The Commission is not persuaded that a modification to the designation procedure is warranted. As stated in the interim rule the Commission does not have the information needed to accurately identify qualifying tight formations.[12] The interim rule's designation procedure was established to enable the Commission to fully utilize the information and expertise available to jurisdictional agencies and to thereby *prevent* undue delay in the identification of tight formations. To the extent that other Federal agencies have studied certain tight formations, we expect this information will be available to jurisdictional agencies and will facilitate the jurisdictional agency process.

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[12] The Commission adopted this procedure in response to comments which suggested that the Commission should rely on the jurisdictional agencies' information and expertise in designating tight formations.

Still another commenter submitted that there are not enough procedural safegards in the interim rule. The rule does not provide producers an opportunity to seek review of a jurisdictional agency's refusal to make a recommendation. Commenters suggested a procedure to allow review in such a case.

Jurisdictional agencies are not obligated to recommend tight formations. The Commission believes the review procedure suggested is unnecessary and would constitute an unwarranted intrusion into the state jurisdictional agency process.

Proposals respecting interim collection authority were also received. One commenter urged that producers be permitted to make interim collections prior to designation of a formation after it has submitted information and certified to the jurisdictional agency that the formation meets the criteria set forth in the guidelines. Pursuant to this proposal, interim collections would be allowed pending jurisdictional agency designation recommendation and final Commission approval. Another comment requested clarification of whether interim collection authority will be permitted prior to designation of the formation upon filing of an application for a well determination.

As discussed above, the procedure in the final rule provides for the expeditious designation of tight formations. The Commission believes that interim collection of the incentive price prior to designation of the formation is inappropriate. However, the Commission in § 273.204 has provided for retroactive collection for gas produced from qualifying wells in designated tight formations.

VIII. Guidelines

The interim rule provided that the Commission would approve the designation of any formation recommended by a jurisdictional agency if it met the three guidelines relating to permeability, gas production, and oil production. Certain of the comments were directed to these guidelines. The Commission has added a guideline that will be discussed below concerning formations or portions thereof which have been authorized to be developed by infill drilling programs.

The interim rule also provided that if a formation met the gas productivity and oil production guidelines but did not meet the permeability standard, then the Commission would consider the recommendation if the jurisdictional agency made an adequate showing that the formation exhibited low permeability characteristics and that an incentive price would be necessary. No comments specifically addressed this provision, and it has been adopted without change in § 271.703(c)(2)(ii) of the final rule.

A. Permeability Standard

The interim rule required that the estimated *in situ* gas permeability, throughout the pay section be 0.1 millidarcy or less. A few commenters suggested that this standard is still unduly restrictive and will disqualify many formations that should be considered "tight." Higher standards ranging from 0.15 millidarcy to 0.5 millidarcy were suggested.[13]

Several arguments were presented in support of a greater permeability threshold. First, average permeability depends on the number of wells drilled and their location in the formation. Since most tight formations have not been developed extensively, the average permeability of a small number of wells would probably not be representative of the formation as a whole. Thus, the amount of necessary preliminary drilling and the greater expense and time involved in *in situ* permeability testing requires a millidarcy standard that is flexible enough to warrant the increased costs.

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[13] The NPC study and "various DOE reports" are cited for the proposition that a formation may be "tight" if it has a permeability of 1.0 millidarcy.

Some comments urged that the permeability standard be eliminated. One commenter asserted that a permeability determination of 0.1 millidarcy requires an expensive drawn down and build up test. It was proposed that a 30-day flow test based upon the depth criteria set forth in the interim rule be the sole factor in determining if a zone is tight.

Another alternative presented was that the designation by the jurisdictional agency should be based solely on production rates from newly drilled wells that had been tested in accordance with the procedures set forth by the United States Bureau of Mines Monograph No. 7. This commenter stated that the gas productivity standard should be retained until such time as information based on the testing of actual wells indicates that a revision would be appropriate.

The Commission remains cognizant of the difficulties inherent in adopting a permeability guideline. However, the objective of the rule is to identify and provide incentives for the development of tight formations, not to provide incentives to develop all formations with low pre-stimulation production rates. The Commission still believes that the problem presented by formations of extremely variable characteristics is not present in many tight formations and that estimates of average permeability may reasonably represent the permeability that will be encountered from one location to the next. However, if the average permeability cannot be reasonably estimated or if the average permeability does not fall within the 0.1 millidarcy guideline, then under the alternate guideline the formation may still be recommended for designation if the jurisdictional agency makes an adequate showing that the incentive price is necessary for production of gas from the formation because the formation is high-risk and high-cost and has low permeability characteristics.

B. Gas Production Standard

The interim rule set forth maximum allowable production rates. One commenter suggested that the gas productivity standard should only be applied to formations from zero to two thousand feet in depth since the costs of drilling and completing deeper wells multiply at a rate disproportionate to those for shallower drilling. If the standards for deeper wells are retained, the commenter urged a 35 percent higher price.

A similar argument was made that the straight payout of original drilling, completion, and equipping costs over a more feasible period than is indicated by the present gas productivity standard would be more appropriate for these high-risk ventures. This commenter proposed that in the event a Btu-equivalent price is not allowed, then the maximum allowable production rate should be increased.

The Commission believes that the higher incentive maximum lawful price provided in this rule will be adequate to cover the increased costs of equipping and completing deeper wells. Therefore, a revision to the gas productivity formula is unnecessary.

C. Production of Crude Oil

The interim rule provided that no well drilled into the recommended tight formation should be expected to produce more than five barrels of crude oil per day. This requirement was added to ensure that the gas is not produced with any more than a *de minimus* amount of oil. The production of more than five barrels of oil per day would, in itself, create an incentive for the development of the formation. One commenter claims that this limitation is unclear since "oil" is undefined and questioned whether it would include "condensate" from gas wells.

The interim rule and § 271.702(a)(3) of the final rule refers to the definition of "crude oil" contained in § 270.102(b)(5) of our regulations. Thus, as defined, crude oil includes any mixtures of hydrocarbons that are liquid in underground formations and remain liquid at atmospheric pressure.

Another commenter suggested that this guideline should be modified to provide that:

> * * * no well drilled into the recommended tight formation is expected to produce, *without stimulation*, more than five barrels of crude oil per day . . .

The commenter asserted that the addition of the phrase "without stimulation" appears in the gas productivity standard and should be tracked here to remove any ambiguity. We agree. Section 271.703(c)(2)(i)(C) has been so modified in the final rule.

D. Infill Drilling

In the preamble to the interim rule, the Commission stated that its objective in establishing the incentive program—

> Consist[s] of identifying and including tight formations that could not be commercially developed absent application of enhanced production techniques, and excluding the types of development activities that could occur under the otherwise applicable maximum lawful prices. (*mimeo* at p. 24).

The Commission did not adopt any of the several alternatives considered which would have mechanically excluded infill or developed portions of an otherwise tight formation. The Commission chose instead to rely on the skill and judgment of the jurisdictional agencies to identify and exclude the portions of a formation which would otherwise qualify as a tight formation but which could be developed without the incentive price. The following guidance was provided to jurisdictional agencies:

> While new infill wells are not excluded from qualification under this rule, jurisdictional agencies should be sensitive to the fact that some portions of tight formations have been developed to such an extent as to indicate that the incentive maximum lawful price is not necessary to encourage full production of that portion of the formation. If the agency has information which indicates such portions can be developed without the incentive price, such portions should be excluded from the jurisdictional agency's recommendation (*mimeo* at p. 27).

Subsequent to the adoption of the interim rule, it has come to the Commission's attention that there is some uncertainty regarding the appropriateness of recommending formations or portions of formations that are currently being developed by infill drilling programs. To clarify this uncertainty and to give effect to the policy enunciated in the interim rule, the Commission has added a new guideline, at § 271.703(c)(2)(i)(D). Under this guideline, if a formation or portion thereof was authorized to be developed by an infill drilling program prior to the date of recommendation and the jurisdictional agency has information which in its judgment indicates that such formation or portion subject to infill drilling can be further developed without the incentive price established in §271.703(a), then the jurisdictional agency may not include such formation or portion thereof in its recommendation.

Two aspects of this guideline warrant clarification. The guideline has been added to focus jurisidictional agency attention on only those formations (or portions thereof) where development by infill drilling has been authorized *prior* to the date of recommendation. In this situation development of such formation may have been economical at previously available prices and therefore may indicate that the full development could occur absent the incentive price. If information available to the jurisdictional agency indicates that this is the case, it should not recommend the formation or should exclude that portion of the formation from its recommendation. Second, it should be emphasized that once a formation has been approved by the Commission as a designated tight formation, future infill wells will be eligible to receive the incentive price.

A definition of "infill drilling" has been added in § 271.703(b)(6). As defined, "infill drilling" means any drilling that occurs in a substantially developed formation or portion thereof that is subject to requirements respecting well-spacing or proration units which were amended by the jurisdictional agency after the formation or portion thereof was substantially developed and which were adopted for the purpose of promoting more effective and efficient drainage of the reservoirs in such formation. Such amendment may provide for the establishment of smaller drilling or production units or may permit the drilling of additional wells on the original units.

The Commission wishes to emphasize that the infill drilling must have taken place in a substantially developed formation or portion of a formation *after* a jurisdictional agency amendment to well-spacing or proration unit requirements. In some situations, field or spacing rules are in effect and applicable to undeveloped portions of a field and these rules are amended prior to substantial development in order to permit the drilling of wells at closer spacing than permitted by the original rules. Where the original units had not been drilled prior to the creation of the smaller units or prior to the adoption of amended rules which permit the drilling of an additional well on the original unit, drilling in such circumstances would not be covered under this definition.

IX. Contents of Recommendations

The interim rule prescribed information that is required to accompany the jurisdictional agency's recommendation that a formation be designated as a tight formation. The comments criticized the requirement that a jurisdictional agency must submit a map or list locating all wells "which have produced" natural gas from the recommended tight formation. The comments argued that this requirement is unnecessary, burdensome, and may be impossible to meet in cases where records on these wells were either never compiled, were lost, or were destroyed over the years. One comment suggests that the requirement be limited to the identification of wells producing on or after January 1, 1980. Another proposal is that the requirement be retained for only those formations that did not meet the 0.1 millidarcy permeability standard and are being recommended under the alternative standard.

In response to these comments we have reduced the burden by amending § 271.703(c)(3)(iii) of the final rule to require jurisdictional agencies to submit either a map or list which locates wells which are *currently producing* from the recommended tight formation. We have retained the requirement, as amended, so that the Commission can have information indicating how much the formation was developed prior to its being recommended as a tight formation.

X. Environmental Impact

As stated in the interim rule, staff completed an environmental assessment of this rule in which staff concluded that establishing an incentive price would not constitute a major Federal action significantly affecting the quality of the human environment.

The Commission will continue to investigate the possible effects of the tight formations program and will make a final determination as to environmental impact at such time as the jurisdictional agencies submit their recommendations for tight formations. The information of the jurisdictional agencies when they make their recommendations includes information regarding the identification and location of fresh water aquifers which may be affected by development of the formation.

XI. Retroactive Collections

Some commenters questioned whether interim collection authority under §§ 273.202 and 273.203 would be permitted prior to final designation of a formation as a tight formation. As previously stated the Commission is not providing interim collection authority prior to final designation of the formation. However, the retroactive collection provisions contained in § 273.20(a)(1)(ii) of the Commission's regulations are applicable to new and recompletion tight formation gas that qualifies under § 271.703(b) to receive the incentive maximum lawful price set forth in § 271.703(a).

XII. Effective Date

These rules shall become effective as final regulations September 22, 1980.

(Department of Energy Organization Act, 42 U.S.C. § 7101, et seq.; E.O. 12009, 42 FR 46267.

Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432)

Subpart G of Part 271, Subpart B of Part 273, and Subpart B of Part 274, of Subchapter H, Chapter I, Title 18, Code of Federal Regulations, are revised as set forth below, effective as final rules on September 22, 1980.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,184]

45 F. R. 56046 (August 22, 1980)

18 CFR Part 284

[Docket No. RM79–34]

Transportation Certificates for Natural Gas for the Displacement of Fuel Oil

August 15, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts a final rule extending and amending its Order No. 30 program. Under the Order No. 30 program, fuel oil users certified by the Economic Regulatory Administration may purchase natural gas from producers, distributors or pipelines. The final rule authorizes the transportation of such natural gas to end-users for the displacement of fuel oil. The Order No. 30 program is extended until 11:59 p.m. on May 31, 1981.

EFFECTIVE DATE: August 31, 1980.

FOR FURTHER INFORMATION CONTACT:

Robert Platt, Assistant Advisory Counsel, Office of the General Counsel, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357–8433.

Glenn Berger, Office of the General Counsel, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357–8364.

Robert J. Cupina, Office of Pipeline and Producer Regulations, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357–9036

SUPPLEMENTARY INFORMATION:

The Federal Energy Regulatory Commission (Commission), by this order, adopts a final rule extending until May 31, 1981, and amending its Order No. 30 program for the transportation of natural gas to displace the consumption of fuel oil.

I. Background

On May 17, 1979, the Commission issued Order No. 30 which established a short term program authorizing the transportation of natural gas for the displacement of fuel oil (44 FR 30323, May 25, 1979). That order was adopted in response to a proposal of the Economic Regulatory Administration (ERA) of the Department of Energy which was referred to the Commission pursuant to section 403(a) of the Department of Energy Organization Act, 42 U.S.C. 7173(a) (DOE Act).[1]

In Order No. 30, the Commission authorized interstate pipelines to transport natural gas to end-users certified by ERA.[2] In significant part, the Commission determined that the public interest was served by action to displace fuel oil with natural gas in order to relieve demand pressure on distillate and related stocks of petroleum products as the peak winter heating season approached. The Commission perceived the fuel oil shortages would be relieved by the beginning of the next summer period. Hence we terminated the program on June 1, 1980.

On May 12, 1980, the ERA proposed, pursuant to section 403(a) of the DOE

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[1] In a related rule, the ERA established a procedure to certify the eligibility of end-users for this program. 10 CFR Part 595, 44 FR 20398 (April 5, 1979).

[2] The ERA certification procedure is set forth at 10 CFR Part 595.

Act, that the program should be extended for an additional year ending May 31, 1981.[3] The ERA found "that the urgent need to reduce oil imports still exists." No claim was made that a "fuel shortage" exists in absolute terms as was the case in 1979. Rather the rationale was grounded on the general and urgent need to simply reduce oil imports. The Commission sought comment upon the ERA proposal extension by **Federal Register** notice of 45 FR 34264 (May 22, 1980).[4]

While section 403(a) of the DOE Act authorizes the Secretary of Energy to propose rules with respect to any function within the jurisdiction of the Commission, section 403(b) of that Act provides that the Commission shall have exclusive jurisdiction over such proposals. Accordingly, the Commission proceeded in Order No. 30–B, 45 FR 34364 (May 22, 1980), by requesting written comments [5] and holding a public hearing on June 16, 1980. Order No. 30–B also provide for an interim extension of the Order No. 30 program through August 31, 1980. For the reasons explored below, the Commission amends its rules herein to extend the Order No. 30 program for the full year proposed by ERA.

II. Discussion

A. Adequate Natural Gas Supplies Support Continuation of the Program

A short term oversupply of natural gas now exists in the interstate market. Data filed with the Commission indicate that every major interstate pipeline will enter the 1980–81 winter heating season with storage filled to capacity.[6] Furthermore, data reported to the Commission by the 28 major interstate pipelines indicate that 6,288.8 Bcf of natural gas is projected to be delivered during this coming winter as compared with 6,264.3 Bcf for the corresponding period in 1979–80. In addition, telephone surveys conducted by both the Commission staff and the ERA,[7] indicate that several interstate pipelines lack a market for all of the deliverable gas supplies that they have a right to obtain under contract.[8] In general, it appears that in the next nine months, interstate pipelines and their distributors will be able to satisfy current customer requirements with gas remaining which could be made available for short term sales.[9]

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[3] The ERA proposal was published in the Federal Register concurrently with the interim rule at 45 FR 34299.

[4] Consolidated Edison Company of New York, Public Service Electric and Gas, and National Fuel Gas Supply Corporation have filed motions in this docket seeking an extension of the program. Comments have also been filed, some in favor of and others in opposition to an extension. Futhermore, the Commission convened an informal conference on April 2, 1980, to study the nation's natural gas supply outlook. Notice of Informal Conference, Docket No. GP80–76, 45 FR 15944 (March 12, 1980).

[5] Written comments favoring the extension of the program were filed in Docket No. RM79–34 by: Asarco, Inc., Public Service Electric and Gas Company, Air Products and Chemicals, Inc., Anchor Hocking, Southern California Edison Company, Aluminum Company of America, Olinkraft, New England Power Service Company, Northern Natural Gas Co., Montana Power Company, Arizona Public Service Company, Edison Electric Institute, Pacific Gas and Electric Company, Georgia-Pacific Company, Calcasieu Refining Company, Equitable Gas, Public Service Commission of the State of New York, Michigan Wisconsin Pipe Line Company, Salt River Project Agricultural Improvement and Power District, Delhi Gas Pipeline, Northern Natural Gas Company, Tucson Electric Company, Sen. Jacob R. Javits, Sen. Daniel P. Moynihan, and the New York State Congressional Delegation.

Written comments opposing the extension were filed in Docket No. RM79–34 by: New England Gas Distributors, Northern Illinois Gas Company, Petrochemical Energy Group, Tosco Corporation, Process Gas Consumers Group, Georgia Industrial Group, American Iron and Steel Institute, Brooklyn Union Gas Company, and Concerned Municipal Gas Systems.

Written comments were also filed in Docket No. RM79–34 by: Transcontinental Gas Pipeline Corporation, Philadelphia Electric Company, and Bristol-Myers Company.

In addition, oral presentations or written comments were filed in Docket No. GP80–78 by: Gas Research Institute (GRI), Economic Regulatory Administration, Ohio Producers, National Gas and Oil Corporation, Public Service Electric and Gas Company, Texas Oil and Gas Corporation, Edward W. Erikson, William L. Murray, Jr., Harvard Business School Energy Project, Henry B. Taliferro, Jr., Texas Railroad Commission, Interstate National Gas Association of America, Transcontinental Gas Pipe Line Company, Tennessee Gas Transmission, Natural Gas Pipeline Company of America, National LP-Gas Association, Oil jobbers Council, Midwest Fuel Oil Council, American Gas Association, Michigan Consolidated Gas Company, Edison Electric Institute, Consolidated Edison of New York, System Fuels, Inc., Florida Power and Light, Process Gas Consumers Group, American Iron and Steel Institute, Georgia Industrial Group, Petrochemical Energy Group, Public Service Commission of the State of New York, Columbia Gas Systems Service Corporation, New Jersey Natural Gas Company, Northern Natural Gas Company, New England Power Service, Weirton Steel Division of the National Steel Corporation, Independent Petroleum Association of America, and The Honorable John D. Dingell.

[6] FERC Form 8 data.

Several commenters argue that such a short-term assessment of the nation's natural gas supplies overlooks the long-term consequences of a failure to husband current supplies of natural gas for future requirements. The essence of this argument is that it is bad public policy to spend today's excess supplies (even for the admitted benefits resulting from displacement of imported oil) unless we are confident that the current excess will not be needed to meet the priority requirements of tomorrow.

The Commission collected extensive expert opinion on this question at the Informal Public Conference on the Availability and Pricing of Natural Gas and Alternative Fuels, convened on April 2, 1980, in Docket No. GP80–76.[10] Although the projections of the experts vary, nothing in this record supports a conclusion that a short-term extension of the Order No. 30 program would drain pipelines and distribution companies so as to imperil their ability to meet their service obligations in the future.

On the contrary, the concern was raised by numerous parties that a sustained but under-utilized delivery capability in excess of demand could have the principal effect of inducing producers to defer exploration and development efforts. Moreover, pipelines confronting take-or-pay problems may be forced to accommodate the demand deficit by reducing or postponing new supply initiatives. In effect, the brunt of any market softness would really be borne by producers of potential new sources of gas,[11] thus posing a more significant risk to future service than would occur by draining off the short-term excess presently available.

One comment theorized that if the natural gas could be husbanded, such gas could be used to displace premium fuels (such as distillate fuel oil) at some unstated future date, rather than residual fuel oil at present. The Commission does not agree. Of the 13 million barrels of fuel oil displaced by the program through June, 1980, only 2 million barrels were high-sulphur residual fuel oil.[12] Of greater significance, however, is that the comment failed to consider how cost of any such husbanding effort would be borne or that the existing unabsorbed deliverability would have a determental effect upon the development of new long-term supplies.[13]

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[7] June 16, 1980, transcript at 5–6.

[8] Staff obtained the following measure of interstate pipeline surplus from phone calls to the interstate pipelines and from information supplied to the Commission in response to its April 15, 1980, order requesting information on supply situations of 28 interstate pipelines for the upcoming winter. Panhandle Eastern Pipe Line Co. is currently not purchasing 148 MMcf per day of available pipeline supplies and projects a backoff of at least 86 MMcf per day through the winter. Transcontinental Gas Pipe Line Corporation is currently declining to take 300 MMcf per day from its producer supplies but does not expect to be backing off in the upcoming winter. Columbia Gas Transmission Corp. projects a surplus supply of 43 Bcf during the summer with liquefied natural gas (LNG) supplies and a surplus 22 Bcf without LNG, and projects a surplus of 22 Bcf with LNG in the coming winter. (Columbia also expects to totally replace LNG with other supplies if needed in the upcoming winter.) Consolidated Gas Supply Corp. projects a surplus of 14 Bcf during the coming winter without LNG supplies and a surplus of 64 Bcf with LNG supplies. Northern Natural Gas Co. is currently declining to take from its supply sources 250 MMcf per day. Michigan-Wisconsin Pipe Line Co. is expecting to decline to take 24 Bcf of supplies from producer and pipeline suppliers during the upcoming winter.

[9] This current market circumstance is further complicated by take-or-pay obligations which interstate pipelines frequently accepted when attaching new long-term supplies. One indication of the severity of the problems posed by these obligations is the expense data submitted this year by major pipelines in rate proceedings pursuant to section 4 of the Natural Gas Act. For example, Transcontinental Gas Pipe Line Company projects the largest take-or-pay obligation, $157,197,443, for a 12-month test period in Docket RP80–121, followed by Northern Natural Gas Company with $61,940,560 in Docket No. RP80–88.

[10] The record of the conference was made an item by reference in this proceeding. June 16, 1980, transcript at 68.

[11] *See e.g.* April 2, 1980, transcript at 106–07, 109, 173–75.

Over the next nine months, the demonstrably adequate supplies of pipeline system supply gas will most likely cause the actual volumes of direct purchases under this program to be minimal. This is because system supply gas reflects average pipeline acquisition costs, while direct sales are generally at higher prices associated with new or uncommitted gas. Nonetheless, the value of extending the Order No. 30 program should not be underestimated. The program provides a measure of enhanced certainty that users will be able to meet their gas requirements, and so should contribute to a greater willingness on the part of industry and electric utilities to restore natural gas burning capability.

B. Desirability of the Present Program

(1) *Detrimental Dependence on Imported Oil.* When the Order No. 30 program was first proposed by the Secretary of Energy, in March, 1979, the Secretary of the Treasury had just completed a study under section 232 of the Trade Expansion Act of 1962, 19 U.S.C. 1862. That study concluded that "the national dependence on foreign oil was so great as to threaten to impair the national security."[14] The Secretary's findings were based upon both uncertainty as to continuity of supplies and the detrimental effect upon the balance of payments. In March of 1979, the weighted average international price of crude oil was $14.59 per barrel. The current price is $32.00.[15] This recent dramatic price increase further magnifies the adverse effect of oil imports upon the nation's balance of payments. The Secretary of the Treasury found that $42 billion had been spent on oil imports in 1978. That figure has been projected to be $82 billion for 1980.[16] Aside from the balance of payment consequences of America's dependence on foreign oil, this dependence is not without its international strategic costs as well.

In addition to the direct dependence upon foreign oil imports, the nation's domestic refinery capacity has developed to reflect the historic availability of the "sweet" crude oil generally produced in the Middle East. However, new crude oil supplies, including the Alaskan North Slope heavy crude, require different adjustments in refinery operations to account for the changes in sulphur content and density.[17] Because the adjustment in domestic refinery capacity requires both time and available capital, corrective measures are necessary to prevent a detrimental dependence upon imported refined products during the transition. In this regard, the types of fuel oil predominantly displaced to date under the Order No. 30 program, middle distillates and low sulphur residual fuel oil, are the very forms of fuel oil which require the additional refinery equipment (e.g. desulphurizers and coking facilities).[18]

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[12] August 6, 1980 letter of Lynne H. Church, Director of Natural Gas Regulations Division of ERA.

[13] The Commission has taken a number of steps to develop new short-term demand in order to absorb the excess deliverability created by the Natural Gas Policy Act of 1978. (NGPA), Pub. L. 95–621. These measures were designed to be compatible with the high priority that the Commission attributes to promoting the development of system supplies.

The Commission believes that the best method of displacing fuel oil is to increase system supplies of natural gas. As system supplies are increased, customers who use fuel oil when natural gas was in short supply return to the use of natural gas. Thus, the development of system supplies serves to displace fuel oil. Increasing system supplies also protects high priority customers by reducing the likelihood of curtailment.

However, the Commission has also expanded its direct sales program to permit schools, hospitals, essential agricultural users, and process and feedstock users to consume natural gas purchased from producers even if used as boiler fuel. Prior to these amendments, boiler fuel loads were not eligible for direct sale gas, and the participants in the direct sale programs were ineligible to take system supplies for boiler fuel uses.

All of the above initiatives address the ability of a boiler fuel user to obtain natural gas from either pipeline system suppliers or in a direct sale arrangement. The broader question of whether natural gas may be used as a primary fuel in a particular installation is governed by the Powerplant and Industrial Fuel Use Act of 1978 (PIFUA). Pub. L. 95–620, 92 Stat. 3291. Section 301 of PIFUA, 42 U.S.C. 8341, limits the natural gas used in powerplants to levels historically used during 1974 through 1976, (subject to certain exemptions granted by the ERA). However, the ERA, as part of its comprehensive fuels policy, grants temporary public interest exemptions from the PIFUA when consistent with the objectives of the Act and national policy. Although the Commission's exercise of its Natural Gas Act authority significantly affects the use of natural gas transported in interstate commerce, the Secretary of Energy's authority and responsibilities under the PIFUA are even broader.

[14] Report of the Secretary of Treasury dated March 14, 1979.

[15] Energy Information Administration Weekly Petroleum Status Report, issued August 1, 1980 (No. 0208(31)) at 38. *See* also June 16, 1980, transcript at 60.

[16] August 6, 1980 letter from Lynne H. Church.

(2) *Effects on Refinery Runs.* Several comments, from fuel oil suppliers, suggested terminating the Order No. 30 program on the grounds that the program creates an oversupply of residual fuel oil which in turn causes a lower than normal crude oil refinery run. In other words, the comments predict that refiners would convert a reduced quantity of crude oil into gasoline, fuel oil and other products. Douglas G. Robinson, Deputy Administrator of ERA, testified that the ERA is aware of such an effect upon refinery runs, and that the ERA has been and will continue to monitor such effects.[19] However, recent Department of Energy statistics indicate that refinery runs and refined product stocks are adequate to meet national needs.[20]

Any impact of the Commission's fuel oil displacement program on refinery runs would be regional rather than natonwide and would be indistinguishable from the impact of the ERA special public interest exemption program under the PIFUA. Given the ERA's ongoing commitment to monitor such regional effects (an effort beyond this Commission's resources and expertise), the Commission will continue to defer to the ERA on assessing the program's impact on refinery runs.

Should the ERA's monitoring of the program's effect on refinery runs show that the Order No. 30 program was adversely affecting refinery utilization, the ERA has retained authority to withdraw the certification of eligible users and/or their PIFUA exemptions in an affected region.[21]

(3) *Criteria for Certification of End Users.* The Commission will continue the practice of requiring end-users to obtain certificates of eligible use from the ERA pursuant to 10 CFR Part 595 as a condition for the authorization of covered transportation under this program.

One of the factors considered by the ERA in certificating eligible uses is that the natural gas will displace fuel oil rather than coal. This restriction reflects both the legislative intent of the PIFUA as well as a recognition of the long-term need to shift both fuel oil and natural gas users on to more abundant or renewable energy resources.

Although the possibility of excluding high sulphur residual fuel oil users was raised, the Commission does not see the need to foreclose the ERA from exercising its discretion to certify such users. Given that high sulphur residual fuel oil is generally less expensive than the delivered cost of natural gas under this program;[22] the use of natural gas to displace high sulphur residual fuel oil is unlikely to occur in current market conditions.

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[17] *See* written comments of Douglas G. Robinson, April 2, 1980, at 24–27.

[18] *Id.*

[19] April 2, 1980, Transcript at 61–62, 71, 83–84. See also 10 CFR 595.05.

[20] The Energy Information Administration Weekly Petroleum Status Report (No. 0208 (80–31)) issued August 1, 1980 indicates that primary stocks of motor gasoline is 11.1% above last year's level, residual fuel oil stocks are 3.0% below levels a year ago, and middle distillate stocks are 27.9% above levels a year ago. In addition, crude oil imports are 19.2% lower than last year, and the four-week average of distillate imports are 54.9% lower than the level one year ago.

[21] April 2, 1980 Transcript at 88.

[22] April 2, 1980, Transcript at 314–15, 330.

Fuel oil suppliers also suggested restricting the program to the displacement of fuels from offshore refineries. As the August 6 letter from Lynne H. Church, Director of the Natural Gas Regulations Division of ERA, indicates, 66% of the fuel oil displaced to date under the program was in East Coast markets [23] which rely heavily upon fuel oil refined offshore. Given this trend, and the regional nature of fuel oil spot markets, the Commission does not see the need to restrict the ERA's discretion by limiting the program to the displacement of fuel oil refined offshore.

One comment suggested expanding the program to include new powerplants which demonstrate an overall oil saving. Given the short-term nature of the Order No. 30 program and the overriding long-term need to switch powerplants from both fuel oil and gas onto coal and other more abundant energy sources, the Commission believes that suggestion is neither feasible nor desirable.

Another comment suggested that the program be extended to include interstate pipelines as purchasers who will in turn sell natural gas to fuel oil displacement users from the pipeline's system supplies. The Commission does not believe that such an amendment is necessary, for these categories of transactions are already authorized under Subparts B through E of Part 284. So long as natural gas will become a part of the interstate pipeline's system supply, the pipelines may purchase gas under section 311(b) or 312 of the NGPA and transport gas under section 311(a) of the NGPA. The deliveries to end-users authorized by Order No. 30 do not meet the system supply requirement imposed by other Part 284 authorizations.

One comment sought clarification of the role of the ERA certification program with respect to the review of the seller of the natural gas. The Commission views the provisions of both these and the ERA regulations as unambiguous on this point. The ERA examines and certifies the proposed participating end-user rather than the person who sells the natural gas. Although Subpart F of Part 284 does impose different eligibility criteria depending upon whether the seller is a producer, distributor, intrastate pipeline, or interstate pipeline, the responsibility for determining whether those eligibility criteria are met rests with the transporting pipeline, and ultimately with the Commission.

(4) *Self-implementation.* Order No. 30 sought to permit fuel oil displacement transactions which satisfy the eligibility criteria of § 284.202 to go forward with a minimum of regulatory delay. Accordingly, the Commission relied upon its authority under section 311(a) of the NGPA to authorize the transportation of natural gas on a categorical basis. The Commission also exercised its exemptive authority under section 7(c)(1)(B) of the Natural Gas Act, to exempt the construction of certain facilities (§ 284.204) and certain other transportation not otherwise eligible for section 311(a) authorization. Such actions were consistent with the Commission's determination that the original Order No. 30 program was premised on a perceived fuel oil emergency. Our extension of this program is not similarly grounded on the determination that an emergency in fuel oil supply today exists. The Commission therefore will withdraw the section 7(c)(1)(B) authority in Order No. 30 transactions, after August 31, 1980.

Transportation authorized pursuant to section 311(a) of the NGPA by § 284.202 may commence immediately upon the issuance of an ERA certificate of eligible use. The Commission takes this opportunity to emphasize that in the case of an intrastate pipeline selling natural gas to the eligible user, existing regulations require any application under § 284.123(b)(2) for Commission approval of a transportation rate allowance incorporated in the sales price to be filed by the selling pipeline as a condition to the commencement of the sale. Once such an application is filed, the sale may proceed without prior Commission approval, except that, the sales price will be subject to refund under § 284.2.

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[23] The August 6 letter refers to Petroleum Allocation for Defense District (PADD) I, which includes all states on the Atlantic coast.

(5) *Direct Sales of Natural Gas.* Some comments contend that fuel oil displacement can be better achieved through the sales of interstate pipeline system supplies to traditional boiler fuel customers. As a result, the comments argue that a separate program for the transportation of natural gas outside the scope of pipeline system supplies (and interstate pipeline curtailment plans) is unnecessary and has a detrimental effect upon the acquisition of new pipeline supplies. One comment suggests that the eligible user be required to demonstrate that supplies are not available from its pipeline and distributor suppliers as a prerequisite to participation in the Order No. 30 program.

These concerns are not supported by our experience during the first year of the program. Although § 284.208 provides interstate pipelines with the opportunity to intervene and seek for their own system the natural gas supply proposed for sale to an eligible user, no pipeline has yet expressed such a need for the gas in any Order No. 30 proceeding. The pattern of actual sales occurring under the Order No. 30 program indicates that distributors and some interstate pipelines do not have a market among traditional customers for all natural gas presently under contract. Conversely, eligible users who were able to obtain natural gas from traditional suppliers did not consummate transactions under Order No. 30.[24]

Although the direct sale of natural gas is an effective means for targeting fuel oil displacement gas to specific end users, the Commission reaffirms its intent to give first priority to interstate pipeline system supplies. Interstate pipeline off-system sales to eligible users from general system supply will be subject to case-by-case scrutiny based upon an evidentiary record assembled by an Administrative Law Judge. One of the issues to be considered is the price charged and the treatment of the revenues by the interstate pipeline (§ 284.208(d)(2)). This inquiry will extend to whether the pipeline's other customers are disadvantaged by the sale to the eligible user. Should the transaction be priced in terms which effectively require subsidization by system supply customers (who may also be displacing fuel oil) a strong showing would have to be made to establish how such a circumstance would be consistent with the public interest.

Moreover, when a transporting pipeline lacks sufficient capacity to transport both system supplies and Order No. 30 volumes, § 284.205(f) requires that the Order No. 30 volumes are first to be interrupted.

C. *Long-Term Disposition of Supply Imbalances*

As outlined above, the excess deliverability of natural gas supplies committed to pipelines and distributors is likely to recur. Although the Order No. 30 program is a valuable means of directing some of the excess deliverability to serve an important national interest in displacing imported oil, it is not necessarily the optimum program for fulfilling the Commission's regulatory objectives. In particular, although the program has proven successful in satisfying the short-term goal of rebuilding critically short fuel oil supplies, the Order No. 30 program does not advance the Commission's primary objective of developing a balanced load of end-users on the interstate pipeline systems. The original fuel oil displacement program proposed by ERA was to be limited to a year's duration subject to renewal for a second year.[25] Similarly, the current ERA proposed extension is confined to limit the total duration of the program to a two-year period.[26] Although this rule would extend the program to complete the full two years originally envisioned by ERA, the Commission wishes to emphasize that any further extension of the program would be well beyond the contemplation of this short-term structure. Accordingly, all participating end-users should plan to assure that alternative energy supplies will be available upon the final termination of the program in May 1981.

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[24] June 16, 1980 transcript at 12.

By that time, the Commission expects to implement more effective programs to dispose of excess natural gas deliverabilities. It is our objective to reassess current policies and programs and so develop a comprehensive long term policy prior to May 31, 1981.

III. Section-by-Section Analysis of Amendments

Section 284.201(e) has been amended to extend the Order No. 30 program until May 31, 1981.

Section 284.202(a) has been amended by authorizing covered transportation under section 311(a)(1) of the NGPA if such transportation is on behalf of an intrastate pipeline or local distribution company and the sale of such natural gas is a first sale. The term "first sale" is defined in section 2(21) of the NGPA. Natural gas eligible for this authorization cannot have been committed or dedicated to interstate commerce on November 8, 1978. The effect of this amendment is to implement producer sales of natural gas for fuel oil displacement either under section 311(a) of the NGPA (for transportation on behalf of an intrastate pipeline or local distribution company) or under the § 1.32 shortened hearing procedure for section 7(c) certificate authorization.

Section 284.204 is amended by withdrawing the exemption regulation promulgated under section 7 of the Natural Gas Act. Although the exemption rule ceases to apply on September 1, the amendment continues the requirement preventing any costs associated with the construction or operation of facilities by a natural gas company under this subpart from being included in the natural gas company's jurisdictional rates.

Section 284.205(c)(2)(ii) is amended by only requiring a recertification of eligible use by the Administrator pursuant to 10 CFR 595.03, if it is necessary.

Under the present § 284.206, volumes of natural gas purchased pursuant to Order No. 30 are not considered as either a natural gas supply or market in a determination of an interstate pipeline's customer requirements for present or future allocations of natural gas during periods of natural gas curtailment. Because such a provision may circumscribe the latitude of the Commission and the ERA in implementing Title IV of the NGPA, we do not view the extension of § 284.206 to cover any further volumes as desirable. Section 284.206 is amended to limit the effect of this existing provision to volumes of natural gas purchased prior to September 1, 1980.

Section 284.207 is amended by no longer requiring a certified copy of any currently effective determination by a jurisdictional agency under NGPA section 503 and Part 274 of this chapter and applicable to the natural gas to be transported. The affidavit formally requested is no longer required. An affidavit, that natural gas purchased in a first sale by an eligible user was not purchased at a price above the maximum lawful price, is required.

Section 284.208 has been amended to utilize the statutory hearing procedure for natural gas which is not committed or dedicated and is purchased by the eligible user in a first sale. The hearing shall be conducted in accordance with § 1.32 of this chapter. In all other Order No. 30 cases not eligible for self-implementing authorization under section 311(a) of the NGPA, an evidentiary hearing will be conducted before an administrative law judge.

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[25] Proposed 18 CFR 157.204 (c) and (d), 44 FR 17644 (March 22, 1979).

[26] 45 FR 34299.

IV. Effective Date

The Commission finds that the public interest is best served by the continuation of the fuel oil displacement program for an additional nine months. In order to avoid a disruption of on-going transactions authorized under Order No. 30, this rule must take effect before September 1, 1980. For this reason, the Commission finds good cause to waive the 30-day requirement set forth in 5 U.S.C. 553(d) and to make this rule effective on August 31, 1980.

(Natural Gas Act, 15 U.S.C. 717–717w, Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432; Department of Energy Organization Act, 42 U.S.C. 7101–7352, E.O. 12009, 42 FR 46267)

In consideration of the foregoing, Part 284 of Chapter I, Title 18, Code of Federal Regulations, is amended, as set forth below, effective August 31, 1980.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,185]

45 F. R. 56340 (August 25, 1980)

18 CFR Part 141

[Docket No. RM80–71; Order No. 100]

Electric Utilities; Order Discontinuing Reporting Requirements

August 18, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) hereby discontinues FPC Form No. 12–A (18 CFR 141.52), and Form No. 12–D (18 CFR 141.55), which require various reports and information on the generation, transmission or distribution of electricity. These forms are eliminated because the Commission no longer needs the data reported thereon to carry out its regulatory responsibilities.

EFFECTIVE DATE: August 18, 1980.

FOR FURTHER INFORMATION CONTACT: Daniel G. Lewis, Federal Energy Regulatory Commission, Office of Electric Power Regulation, 825 N. Capitol Street, NE., Mail Stop 300 RB, Washington D.C. 20426 (202) 376–9227.

I. Background and Summary

The Federal Energy Regulatory Commission (Commission) by this rule eliminates from its regulations the following Federal Power Commission (FPC) forms and concomitant reporting requirements: Form No. 12–A, "Power System Statements for Class III, IV, and V Systems" (18 CFR 141.52); and Form No. 12–D, "Power System Statement for Class III Systems Having Annual Energy Requirements of Less Than 5,000,000 kWh and Class IV and V Systems Where Requested" (18 CFR 141.55).

Form No. 12–A requires the reporting of information on electric equipment, generation, energy received and delivered, system peaks, energy delivered to ultimate consumers, system dependable and assured capacity, and contemplated changes in capacity. Information required by this form is currently being collected for the Commission by the Energy Information Administration (EIA).

Form No. 12–D requires the reporting of information on generation, energy received and delivered, system peaks, energy delivered to ultimate consumers, contemplated changes in system generating plants, and electric equipment which the reporting company owned or operated. Information required by this form is now also collected by EIA.

The forms were devised and promulgated by the Federal Power

Commission (FPC) (the Commission's predecessor agency) pursuant to the authority granted in sections 301, 309 and 311 of the Federal Power Act (FPA).[1] The authority under section 311 was transfered to the Secretary of Energy pursuant to section 301(b) of the Department of Energy Organization Act[2] (42 U.S.C. 7101, *et seq.*). The Secretary in turn delegated this authority to the Economic Regulatory Administration (ERA) (Department of Energy Delegation Order No. 0204-4 (10 CFR 1001.1)), and to the Commission to the extent necessary to perform its other functions (Delegation Order No. 0204-1, 42 FR 55637 (October 18, 1977)).

The Commission has determined, however, that the data required by Form Nos. 12-A and 12-D are not sufficiently central to its functions to justify continued collection of the data by this Commission. In view of this, the Commission is hereby eliminating from its regulations those sections which provide for the Commission's collection of the information pursuant to those forms.

II. Effective Date

The elimination of Form Nos. 12-A and 12-D simply amends the Commission's regulations to reflect that the Commission will no longer require the information gathered from these forms.[3] For this reason, the requirement to report information pursuant to these forms will be eliminated as of August 18, 1980.

The Commission accordingly finds that notice and public procedure are unnecessary pursuant to 5 U.S.C. 553(b), and that there is good cause under the 5 U.S.C. 553(d) to make the amendments in this rulemaking effective immediately. (Department of Energy Organization Act, (42 U.S.C. 7101, *et seq.*); Federal Power Act, as amended, (16 U.S.C. 792, *et seq.*); Department of Energy Delegation Order 0204-1, 42 FR 55637 (October 18, 1977); Department of Energy Delegation Order 0204-4 (10 CFR 1001.1))

For the foregoing reasons, Title 18 of the Code of Regulations is amended in Part 141 as provided below, effective immediately.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,186]

45 F. R. 54033 (August 14, 1980)

18 CFR Part 290

[Docket No. RM79-6; Order No. 48-B]

Collection of Cost of Service Information Under Section 133 of the Public Utilities Policies Act of 1978

August 7, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final Rule.

SUMMARY: The Federal Energy Regulatory Commission hereby amends its regulations regarding the collection of cost of service information under section 133 of the Public Utilities Regulatory Policy Act of 1978 to provide utilities required to submit data under that section with instructions for submitting the required information.

EFFECTIVE DATE: August 7, 1980.

FOR FURTHER INFORMATION CONTACT: Daniel G. Lewis, Assistant to the Director, Office of Electric Power

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[1] Form Nos. 12-A and 12-D were established under FPC Order No. 183 and were amended by Order Nos. 224 and 312.

[2] Section 301(b) provides that powers vested in the FPC under the FPA and the Natural Gas Act (NGA) (15 U.S.C. 717) which were not transferred to the Commission by Title IV of the DOE Act are vested in the Secretary.

[3] The ERA, which is responsible for utilizing the information from these forms, has determined that it needs this information to perform its statutory responsibilities. The ERA is, however, authorized to propose and implement its own regulations and to obtain approval from the Office of Management and Budget for the future collection of the data.

Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 376-9227.

SUPPLEMENTARY INFORMATION:

Background

On September 28, 1979, the Federal Energy Regulatory Commission (Commission) issued Order No. 48, containing final regulations implementing section 133 of the Public Utility Regulatory Policies Act of 1978 (PURPA).[1] On January 4, 1980, the Commission issued Order No. 48-A, granting in part and denying in part petitions for reconsideration of certain provisions of Order No. 48.[2]

Section 290.102(b) of Order No. 48 provides that the information required to be submitted by utilities "shall be submitted on suitable standard forms prescribed by the Commission or in any form otherwise determined by the Commission." The present order amends § 290.102 to provide respondent utilities with instructions for submitting the required information by November 1, 1980. The order further states the Commission's intention to consider refinement and extension of these instructions following its review of the first submissions under these regulations.

In seeking to fulfill the purpose of section 133, Order No. 48 places new and extensive reporting requirements on those electric utilities covered by Title I of PURPA. Whether these reporting requirements should include new standard forms, thereby assuring uniformity among the submissions, has not yet been determined. Uniform submissions would facilitate use of the information by some interested parties[3] and any compliance review that is necessary. However, there are arguments against the prescription of standard forms, including the fact that many of the required data have already been developed by respondent utilities for their own purposes and would have to be transcribed to such standard forms as we might prescribe. Because the time in which utilities must submit their first reports is only about three months away, it is urgent to provide respondents with basic instructions now so as to enable them to meet the first reporting date. This can be done with instructions that permit latitude in format. Even if we determine now that standard forms are desirable, their preparation and adoption would take more time and would jeopardize effective compliance, which would not serve the overall purposes of the law. We think it better to give respondent utilities the opportunity to take advantage of the existing report formats and media, where these are applicable and thus seek the means to minimize new reporting costs to the extent possible.

However, it is important that the data be available to users in convenient form. The required information is expected to be used, at least initially, on a case by case basis, involving one utility or a very small number of utilities. The Congressional purpose was to provide for the availability of information that would be used primarily by persons interested in retail electric rate proceedings in the various states. As a consequence, the filed information must be ready for use in locations that are readily accessible to such interested persons. For this reason, the filings must be self-contained. The potential users must not have the burden from which the Congressional act would relieve them of having to depend on data in a variety of reports that the utilities would file with Federal or State agencies, some of which might not only be inaccessible, but even unknown to some interested persons.

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[1] 44 FR 58.687 (1979).

[2] 45 FR 2.023 (1980).

[3] In particular, this would appear pertinent to the intervention activities of the Secretary of Energy, as well as to those users or other interested persons who express a national concern with retail electric ratemaking procedures, such as some industrial groups and some consumer or conservationist groups.

Summary

Reports filed under Order No. 48 must be legible and complete. They must be capable of being understood by a person who is familiar with the data requirements of Order No. 48 and generally familiar with utility accounting and operating terminology and practices.

It is our conclusion that a minimal and adequate reporting format consistent with the objectives set forth above is a set of data presentations, of the respondent utilities' design and choosing, having clear and unambiguous correspondence to the paragraphs and subparagraphs of the regulations that specify data requirements. The presentations must be clearly labeled as to the paragraph of the regulations treated, and must be arranged in the order in which the items are to appear.

As an appendix to this order, but not a part of it, the Commission has included a Staff Advisory Statement describing specific formats that may be used, at each respondent utility's option, for reporting certain information specified in the regulations. Commission Staff is hereby directed to review the submitted information and by February 1, 1981, advise the Commission as to the need for refinement and extension of the reporting instructions, including the need for standard forms. To the extent that standard forms are included in Staff recommendations, such forms may or may not be similar to those included in the Staff Advisory Statement attached hereto. The comments of utilities and other interested parties will be sought on any standard forms proposed in Staff recommendations.

Effective Date

The revision to § 290.102(b) is intended to inform persons required to file data under 18 CFR Part 290 by November 1, 1980, of the way in which such data to be submitted is to be organized. There is an immediate need for regulations to give direction to those who are preparing data submissions for the approaching deadline. In addition, the regulation is a procedural one relating to the format and organization of data submittals already required by Part 290. For these reasons, good cause exists to adopt this revision effective immediately.

(Public Utility Regulatory Policies Act, (16 U.S.C. 2601–2645). Department of Energy Organization Act (42 U.S.C. 7101–7352), Exec. Order No. 12009, 3 CFR Part 142 (1978))

In consideration of the foregoing, the Commission revises Part 290 of Chapter I, Title 18, *Code of Federal Regulations*, as set forth below.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,187]

45 F. R. 60898 (September 15, 1980)

18 CFR Parts 141 and 260

[Docket No. RM80-59—Order No. 101]

Order Revising Annual Reports for Public Utilities and Licensees, and for Natural Gas Companies (Class C and Class D)

Issued: September 5, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) hereby revises Form No. 1-F, "Annual Report for Public Utilities and Licensees (Class C and Class D)" (18 CFR 141.2), and Form No. 2-A, "Annual Report for Natural Gas Companies (Class C and Class D)" (18 CFR 260.2). The revisions should reduce the reporting burdens imposed by these two forms (by approximately 63% in the case of Form No. 1-F, and 30% in the case of Form No. 2-A) by eliminating certain data requirements which the Commission no longer needs to carry out its regulatory functions. The changes are a product of the Commission's ongoing effort to eliminate unnecessary reporting burdens.

EFFECTIVE DATE: October 6, 1980.

FOR FURTHER INFORMATION CONTACT:

James Kitchen, Office of Chief Accountant, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Room 3408N, Washington, D.C. 20426. (202) 357-9212.

Elaine Dawson, Office of Chief Accountant, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Room 3405N, Washington, D.C. 20426. (202) 357-9190.

I. Background

On May 23, 1980, the Federal Energy Regulatory Commission (Commission) issued a Notice of Proposed Rulemaking (45 FR 36428, May 30, 1980). This Notice proposed to revise Form No. 1-F, "Annual Report for Public Utilities and Licensees (Class C and Class D)," and Form No. 2-A, "Annual Report for Natural Gas Companies (Class C and Class D)," [1] to reflect the results of the Commission's ongoing validation program, the purpose of which is to reduce the reporting burden on the industries regulated by the Commission.[2]

Form No. 1-F annually collects from privately owned electric utilities information concerning the Balance Sheet Statement, Statement of Income and related items.

Form No. 2-A is annually filed by natural gas companies and collects data concerning natural gas operating revenues, expenses and sales.

The proposed deletions will cause an estimated 63 percent reduction in the reporting burden for Form No. 1-F and an estimated 30 percent reduction for Form No. 2-A.

II. Revisions to Forms

A. Form No. 1-F [2]

By this rulemaking, the Commission eliminates 510 of the 811 data items now prescribed on Form No. 1-F. Of the 510 items, 448 are deleted by elimination of reporting requirements for the following schedules:

Schedule	Page
Security Holders and Voting Powers	3
Officers and Directors	3
Accumulated Provisions for Depreciation and Amortization of Utility Plant	6
Capital Stock	6
Long-Term Debt	6
Electric Sales Data for the Year	7
Sales of Electricity for Resale	7
Electric Operation and Maintenance Expenses	7
Purchased Power	11
Utility Plant	11
Generating Station Statistics	12
Transmission Line Statistics	12
Transmission Lines Added During Year	12
Investment Tax Credits Generated and Utilized	13
Accumulated Deferred Investment Tax Credits (Account 255)	14
Expenditures of Certain Civic, Political, and Related Activities	15

The remaining 62 data items are eliminated by deleting the "Increase or (Decrease)" data requirements of the Comparative Balance Sheet (columns (d) and (h) of schedule pages 4 and 5, respectively). In addition, the Commission has decided to eliminate Instruction 7 of the Statement of Income for the Year (schedule page 9).[3]

B. Form No. 2-A [4]

Form 2-A is changed by deleting 277 of the 907 currently prescribed data items. The reductions are accomplished by:

(1) Deletion of the Principal Business and Address column of the "Officers

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[1] A Class C electric utility or natural gas company is one having annual electric or gas operating revenues of $150,000 or more but less than $1,000,000. A Class D electric utility or natural gas company is one having annual electric or gas operating revenues of $25,000 or more but less than $150,000.

[2] FERC Form No. 1-F (Attachment A) and Form No. 2-A (Attachment B) are not being printed by the Federal Register. Copies are available in the Office of Public Information.

[2] Attachment A.

[3] A similar instruction has been proposed for deletion from Form No. 1 (Docket No. RM80-55, NOPR issued July 10, 1980, 45 FR 47705, July 16, 1980) because it is no longer necessary for the Commission's regulatory purposes. Instruction 7 is eliminated for the purpose of consistency.

[4] Attachment B.

and Directors Schedule" (column c, schedule page 3);

(2) Elimination of the "Increase or (Decrease)" data requirement from the Balance Sheet (columns (d) and (h), schedule pages 4 and 5 respectively);

(3) Deletion of Instruction 7 of the Statement of Income for the Year (schedule page 9);[5]

(4) Elimination of columns b through g from Gas Purchases (schedule page 12);[6] and

(5) Deletion of the following schedules:

Schedule	Page
Investment Tax Credits Generated and Utilized	15
Accumulated Deferred Investment Tax Credits (Account 255)	16
Expenditures for Certain Civic, Political and Related Activities	17
Service Interruptions Occurring on the Pipeline System	18

III. Summary of Comments

In response to the proposed rulemaking, the Commission received comments from only one respondent, the International Brotherhood of Electrical Workers (IBEW).[7] The IBEW argued that "it was logical and in the continued public interest" for the Commission to act as "the statutory and primary collector" of the information required on Form Nos. 1–F and 2–A.

However, while the public may have some interest in this information, the Commission cannot thereby justify the continued collection of this data. The Commission, as part of its data validation program, has determined that the information to be deleted from the forms is no longer necessary to the performance of the Commission's regulatory functions. Because of this determination the Commission is relieving the affected respondents from unnecessary reporting burdens.

IV. Public Procedures and Effective Date

The Commission has complied with 5 U.S.C. 553 by providing public notice and an opportunity to participate in this rulemaking. The changes in this Order will be effective 30 days from the date of its issuance for reports to be filed on or before March 31, 1981.

(Natural Gas Act, as amended, 15 U.S.C. 717–717w; Natural Gas Policy Act of 1978, 14 U.S.C. 3301–3432; Federal Power Act, as amended, 16 U.S.C. 792–828c; Department of Energy Organization Act, 42 U.S.C. 7101–7352; E.O. 12009, 3 CFR Part 142 (1978)).

For the foregoing reasons, FPC Form No. 1–F, "Annual Report for Public Utilities and Licensees (Class C and Class D)", prescribed by § 141.2, Chapter I, Title 18 of the Code of Federal Regulations, and FPC Form No. 2–A, "Annual Report for Natural Gas Companies (Class C and Class D)", prescribed by § 260.2, Chapter I are revised by the Commission as set forth in Attachments A and B.

In addition to the foregoing, Parts 141 and 260 of Chapter I, Title 18 of the Code of Federal Regulations are amended by the Commission as set forth below, effective 30 days from the date of issuance.

By the Commission.

Kenneth F. Plumb,
Secretary.

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[5] A similar instruction has been proposed for deletion from Form No. 2 (Docket No. RM80-56, NOPR issued July 1, 1980, 45 FR 40075, July 9, 1980) because it is no longer necessary for Commission regulatory purposes. Instruction 7 is eliminated for the purpose of consistency.

[6] Similar reporting requirements in Form No. 2 were proposed for deletion as unnecessary, and the changes to Gas Purchases are made herein for the purpose of consistency.

[7] The IBEW is a labor union, the members of which are employed in the electrical construction, manufacturing and utility industries.

[¶ 30,188]

45 F. R. 60418 (September 12, 1980).

18 CFR Part 284

[Docket No. RM79-34]

Transportation Certificates for Natural Gas for the Displacement of Fuel Oil

August 29, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Order granting stay.

SUMMARY: The Federal Energy Regulatory Commission (Commission) hereby adopts an Order Granting Stay. The effect of the Order is to stay the amendment to section 284.206 specified in ordering paragraph (6) of Order No. 30–D until after the Commission issues its order on rehearing of Order No. 30–D. Order No. 30–D extended the Commission's fuel oil displacement program for the nine month period from September 1, 1980 through May 31, 1981. (45 FR 56046, August 22, 1980.)

EFFECTIVE DATE: August 29, 1980.

FOR FURTHER INFORMATION CONTACT:
Robert Platt, Assistant Advisory Counsel, Office of the General Counsel, 825 North Capitol Street, N.E., Washington, D.C. 20426, 202–357–8457, or
Glenn Berger, Office of the General Counsel, 825 North Capitol Street, N.E., Washington, D.C. 20426, 202–357–9036.

Order Granting Stay

Issued August 29, 1980.

On August 21, 1980, Consolidated Edison Company of New York, Inc. (Con Ed), filed a petition pursuant to § 1.7(c) of the Commission's Rules of Practice and Procedure, seeking a stay of Order No. 30-D. Order No. 30-D extended the Commission's fuel oil displacement program for the nine month period from September 1, 1980, through May 31, 1981. Although the extension was for the most part subject to the same terms and conditions as the original Order No. 30, Ordering Paragraph (6) of Order No. 30–D amended § 284.206 to limit the effect of that provision to volumes delivered prior to September 1, 1980. § 284.206 currently provides:

> All volumes of natural gas purchased by an eligible user and transported by an interstate pipeline pursuant to this subpart shall not be considered as either a natural gas supply or market in a determination of an interstate pipeline's customer's requirements for present or future allocations of natural gas during periods of natural gas curtailment.

Con Ed intends to file a petition for rehearing alleging that this amendment to § 284.206 is in error. Con Ed alleges that certain of its gas purchase contracts are contingent upon receiving the assurances provided in § 284.206. In order to prevent the possible loss of these supplies to Con Ed while the Commission consideration of its petition for rehearing is pending, a stay of the amendment to § 284.206 will be granted.

The Commission Orders:

The amendment to § 284.206 specified in Ordering Paragraph (6) of Order No. 30–D shall be stayed until after the Commission issues its order on rehearing of Order No. 30–D.

By the Commission. Commissioner Holden voted present.

Kenneth F. Plumb,
Secretary.

[¶ 30,189]

45 F. R. 61610 (September 17, 1980).

18 CFR Part 282

[Docket No. RM 80-16; Order No. 86A]

Disclosed Estimation Methodology Approach for Determination of Volumes of Natural Gas Used for Exempt Purposes Under the Incremental Pricing Program

Issued September 5, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Order granting in part and denying in part rehearing of Order No. 86.

SUMMARY: On May 8, 1980, the Federal Energy Regulatory Commission issued Order No. 86 in this docket. That Order established procedures to be used until November 1, 1981, by industrial users in calculating the volumes of natural gas subject to incremental pricing surcharges (45 FR 31983, May 15, 1980). Three timely petitions for rehearing of Order No. 86 were filed. The petitions filed by Process Gas Consumers Group and Phelps Dodge Corporation are denied. The petition of United Distribution Companies is granted and the regulations are amended to rescind the submetering requirement and to make the estimating procedures effective on a permanent basis.

EFFECTIVE DATE: October 15, 1980

FOR FURTHER INFORMATION CONTACT: Barbara Christin, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8446.

I. Background

On May 8, 1980, the Federal Energy Regulatory Commission (Commission) issued Order No. 86 in Docket No. RM80-16. That order established procedures to be used until November 1, 1981, by industrial users in calculating the volumes of natural gas subject to incremental pricing surcharges (45 FR 31983, May 15, 1980).

Timely petitions for rehearing were filed by United Distribution Companies, Phelps Dodge Corporation, and the Process Gas Consumers Group *et al.* (Process Gas *et al.*).[1] On July 7, 1980, the Commission granted rehearing of Order No. 86 solely for purposes of further consideration. The arguments raised by petitioners are discussed below.

II. Discussion

A. Submetering

In Order No. 86 the Commission postponed the effective date of the submetering requirement and extended the use of the estimating procedures for an additional year, until November 1, 1981. In taking this action the Commission noted its reluctance to rescind the submetering requirement and implement the disclosed estimation methodology approach on a permanent basis. The estimating procedures had only been in effect for four months, "an inadequate period of time for the Commission to determine whether the approach would provide a sound regulatory mechanism on a long term basis". (Order No. 86 at 3-4.) In addition, at the time Order No. 86 was issued the scope of the incremental pricing program was uncertain. A Phase II rule had been promulgated in Docket No. RM80-10 which expanded the incremental pricing program to include all industrial uses of natural gas. That Phase II rule, however, was subject to Congressional review and could not become effective if disapproved by either House of Congress.

United Distribution Companies (UDC), in its petition for rehearing, requested that the Commission adopt on a permanent basis the "disclosed estimation methodology" approach reflected in Order No. 86. They argued that the extensive record in this docket contains "uncontroverted evidence" that submetering is an impractical, expensive, and sometimes impossible method for implementing an already difficult program, and supports the disclosed estimation methodology as a practical method for determining natural gas volumes subject to incremental pricing surcharges.

UDC also argued that, even if the uncertain scope of the Phase II program were a sufficient ground to postpone implementation of the disclosed estimation methodology approach on a permanent basis, such ground no longer exists. On May 20, 1980, the House of Representatives passed a Resolution of Disapproval of the Phase II rule. This action limits the scope of the incremental pricing program to natural gas used as boiler fuel by industrial boiler fuel facilities.

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[1] Joint petition for rehearing filed by the Process Gas Consumers Group, the American Iron and Steel Institute, and Republic Steel Corporation.

The Commission has reviewed the record in this docket and is persuaded by the arguments set forth in UDC's petition. The estimating procedures have now been in effect for almost eight months and continue to illustrate that they provide a practical method for determining volumes of natural gas subject to incremental pricing surcharges. Accordingly, the Commission amends Order No. 86 to rescind the submetering requirement and make the disclosed estimation methodology approach effective on a permanent basis.

B. Self-Help Supplies

The petition for rehearing filed by Process Gas *et al* asked that the Commission clarify or modify § 282.207(c)(3) to provide that an end-user has complete discretion to designate the end-uses for self-help volumes of natural gas in these situations in which the user's own gas is transported through its own pipeline facilities under neither a Commission program nor a contract with another entity.

The Commission rejects this proposal. The requirement for prorating self-help supplies is clearly set forth in § 282.207(c)(3)(iv) of the regulations. If the self-help supplies described above are commingled with utility-supplied volumes then, for purposes of incremental pricing, the user must prorate its self-help supplies among all its end-uses.

Process Gas *et al.* also asked the Commission to modify Order No. 86 to permit a user to designate for boiler fuel uses volumes of natural gas received under the Order No. 533/Order No. 2 program (Order No. 533 program).[2] The Commission declines to so modify Order No. 86.

The Order No. 533 program establishes a direct sale program for process and feedstock users of natural gas. The amendments to this program promulgated in Order No. 52[3] permit customers to receive natural gas from interstate system supplies or other direct sale programs for low priority uses without jeopardizing their right to receive direct sale gas under the Order No. 533 program for process and feedstock uses. Although specific end-use restrictions on an entire facility have been removed by Order No. 52, the volumetric limits retained demonstrate the Commission's intention to attribute natural gas received under the Order No. 533 program to process and feedstock uses. Accordingly, as the Commission stated in Order No. 86, volumes of natural gas received under the Order No. 533 program shall be deemed for purposes of incremental pricing to be consumed for uses other than boiler fuel. (Order No. 86 at 11–12.)

C. Retroactive Applicability of § 282.207(c)(3)

Under the final rule in Order No. 86 some users were relieved of the requirement in the interim rule to prorate volumes of self-help supplies among all end-uses. The final rule provides for such proration only in those situations where (1) self-help volumes are not transported pursuant to Commission authorization or certification, or pursuant to specified contracts between the buyer and the seller; or (2) a designation of self-help volumes for specified end-uses cannot be supported by plant operating data.

Petitions for rehearing filed by Phelps Dodge Corporation and Process Gas *et al.* requested that the self-help designation rules in Order No. 86 be made retroactive to January 1, 1980. They also argued that the final rules should have provided a mechanism whereby adjustments could be made to pemit refunds of incremental pricing surcharges to those parties who allegedly were improperly assessed during the interim rule's effective period.

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[2] 18 CFR 2.79. FPC Orders Nos. 533, 533–A; FERC Orders Nos. 2, 2–A, and 52.

[3] Order No. 52, Docket No. RM80–1, issued October 5, 1979. 44 FR 60080 (October 18, 1979).

The Commission denies the above requests. The Commission does not view § 282.207(c)(3) of the final regulations as correcting an error but rather as improving the interim rule. Moreover, to grant retroactive relief or adjustments would result in an additional administrative burden that would far outweigh the overall benefit to be gained. Lastly, it should be noted that such retroactive application of § 282.207(c)(3) would result in a detriment to those users whose surcharges were actually less under the interim rule than under the final rule.

D. Treatment of Space Heat

Process Gas *et al.* argued that the formula set forth in § 282.207(c)(1) for the treatment of volumes of natural gas used to raise steam for space heating purposes should be modified.

In Order No. 86 the Commission discussed the argument of Process Gas *et al.* and fully set forth its rationale for the formula adopted in § 282.207(c)(1). (Order No. 86 at 4–7.) The petitioner's request for rehearing on this issue is denied for the reasons stated in Order No. 86.

For the reasons set forth above, the Commission grants in part and denies in part rehearing of Order No. 86 in Docket No. RM80-16. Moreover, the regulations are amended to reflect the Commission's decision to rescind the submetering requirement and make the disclosed estimation methodology approach effective on a permanent basis.

The Commission Orders

For the reasons set forth above the Commission orders:

(1) The petitions for rehearing of Order No. 86 filed by Process Gas *et al.* and Phelps Dodge Corporation are denied.

(2) The petition for rehearing of Order No. 86 filed by United Distribution Companies is granted.

(3) Effective October 15, 1980, Part 282 of Subchapter I, Chapter 1, Title 18, Code of Federal Regulations, is amended as set forth below.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,190]

45 F. R. 64171 (September 29, 1980)

18 CFR Part 282

[Docket No. RM79-48]

Section 206(d) Exemption for Small Industrial Boiler Fuel Facilities From the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978; Notice of Effective Date

September 23, 1980.

AGENCY: Federal Regulatory Commission.

ACTION: Notice of effective date.

SUMMARY: On July 29, 1980, the Federal Energy Regulatory Commission (Commission) issued a final rule (45 FR 52359, August 7, 1980) providing an exemption from incremental pricing surcharges for natural gas used as boiler fuel by small industrial boiler fuel facilities not otherwise exempted by section 206(a)(2) of the Natural Gas Policy Act of 1978 (NGPA). On the same day, the rule was transmitted to Congress for review as required by section 206(d) of the NGPA. During the period for Congressional review, neither House disapproved the submittal. Accordingly, the exemptive rule became effective September 20, 1980, the day following the expiration of the thirty day Congressional review period.

EFFECTIVE DATE: September 20, 1980.

FOR FURTHER INFORMATION CONTACT: Alice Fernandez, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-9095.

Lois D. Cashell,
Acting Secretary.

[¶ 30,191]

45 F. R. 65170 (October 1, 1980)

18 CFR Parts 1 and 282

[Docket No. RM80-78]

Order Delegating Authority Under Section 206(d) of the Natural Gas Policy Act of 1978 to the Director, Office of Pipeline and Producer Regulation, to Grant Exemptions from Incremental Pricing and Amending §§ 1.41 and 282.206

Issued September 23, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Interim rule.

SUMMARY: The Federal Energy Regulatory Commission delegates to the Director of the Office of Pipeline and Produces Regulation the authority of the Commission under section 206(d) of the Natural Gas Policy Act to grant exemptions on a case-by-case basis from incremental pricing under section 201 of the Act. The Commission's regulations concerning incremental pricing exemptions are amended (1) to reflect this delegation, (2) to declare that such an individual exemption is to be granted only in the case of special hardship, inequity, or an unfair distribution of burdens created by incremental pricing requirements, and (3) to direct that such an exemption is to be considered under the same procedures and standards which the Director of the Office of Pipeline and Producer Regulation uses in considering requests for adjustments under section 502(c) of the Natural Gas Policy Act. The Commission's regulation concerning adjustment request procedures is amended to conform to the terms of this delegation and authority.

DATES: The effective date of the interim rule is September 23, 1980. Requests for hearing are due on or before October 3, 1980. If a hearing is scheduled in this docket, it will be held on October 17, 1980 and will be announced on October 6, 1980. Comments are due on or before November 3, 1980.

ADDRESS: All findings should be made with: Office of the Secretary, Federal Energy Regulatory Commission, 825 N. Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Christine P. Benagh, Staff Attorney (202) 357-8446.

I. Summary

The Federal Energy Regulatory Commission (Commission) hereby delegates its authority under section 206(d) of the Natural Gas Policy Act of 1978 [1] (NGPA) to the Director, Office of Pipeline and Producer Regulation, (Director) to exempt on a case-by-case basis industrial facility uses of natural gas otherwise subject to incremental pricing under section 201 of the NGPA.

Section 282.206 of the Commission's regulations is revised to implement this delegation and to prescribe for such exemptions the same standards and procedures employed by the Director in processing requests for Staff adjustments under section 502(c) of the NGPA.

II. Background and Discussion

Section 206(d)(1) of the NGPA establishes the authority of the Commission to exempt, by rule or order, in whole or in part, any industrial facility or category of facilities from the incremental pricing provisions of section 201 or 202. Where entire categories of industrial facilities are to be exempted, a generic rulemaking is appropriate. However, that process is too protracted to grant timely relief to individual companies that have requested an exemption and whose situation requires immediate response.

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[1] 15 U.S.C. § 3346.

The Commission believes that the use of the word "order" in section 206(d)(1) indicates that Congress contemplated and authorized the granting of exemptions on a case-by-case as well as a generic basis.[2] As we noted in *Vertac Chemical Corporation,*[3] individual applications for exemptions from incremental pricing, like requests for adjustments under section 502(c), are better-suited for review and disposition on a case-by-case basis.[4] The rule being issued implements that interpretations by establishing procedures and standards for granting exemptions on a case-by-case basis.

Section 206(d)(2) of the NGPA requires the Commission to submit for Congressional review rules which grant incremental pricing exemptions. As discussed in *Vertac Chemical Corporation,* the Commission believes that Congress wished to review only generic rulemakings issued under section 206(d)(1), not the orders issued in those individualized proceedings addressed in this rule.[5] Accordingly, the Commission does not believe that section 206(d)(2) is applicable to case-by-case determinations addressed by this rule. Section 282.206 of the Commission's regulations is also amended to emphasize that any person may still petition the Commission for the promulgation of an exemptive rule that will, upon final promulgation, be subject to Congressional review.

Upon examining the special circumstances that Vertac Chemical Corporation exhibited, the Commission determined that it would be appropriate there to apply the standards of "special hardship, inequity, or unfair distribution of burdens" found in section 502(c) of the NGPA for processing applications for adjustments.[6] The rule being issued adopts this standard. Because requests for exemptions in individual cases will be based upon allegations of special hardship, inequity, or unfair distribution of burdens, they will require rapid response from the Commission. Such requests can be handled more expeditiously by the Director of OPPR than by the full Commission. Therefore, it is administratively preferable to delegate the authority to issue such exemptive orders to the Director of OPPR. The Director will employ the same procedures established in § 1.41, which apply to requests for adjustments from Commission rules and orders and incorporate the standards being reiterated in § 282.206(b) for purposes of clarity. Section 1.41 is also amended to make it explicit that it is applicable to any exemption granted under § 282.206(b).

For the foregoing reasons, the Commission is amending its rules on an interim basis by delegating to the Director of OPPR the Commission's authority under section 206(d)(1) of the NGPA to issue orders exempting, in whole or in part, incrementally priced industrial facilities from the incremental pricing provisions of section 201 of the NGPA. The Director shall, in issuing such orders, apply the same procedures and standards established in § 1.41 of the Commission's Rules of Practices and Procedures, as amended from time to time.

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[2] The pertinent provision states, "The Commission may, by *rule or order,* provide for the exemption, in whole or in part, of any other incrementally-priced industrial facility or category thereof from the rule prescribed under section 201 (including any amendment under section 202 to such rule)." [Emphasis added.]

[3] Vertac Chemical Corporation, Order Granting Temporary Exemption From Incremental Pricing, Docket Nos. SA80-62 and SA80-63 (issued Aug. 29, 1980).

[4] *Id.* at 3.

[5] *Vertac, supra* note 2 at 2.

[6] Vertac was discharging its debts pursuant to a court's order in discharge of bankruptcy and was still suffering from a severely crippled financial status.

III. Public Procedures and Effective Date

The immediacy of the needs of those requesting exemptions based upon special hardship, inequity, or unfair distribution of burdens creates good cause for the immediate effectiveness of this rule which provides those companies with a more expeditious avenue of relief than full Commission consideration. Therefore, the Commission finds it to be in the public interest to dispense with notice and comment under 5 U.S.C. 553(b) and to make this rule effective immediately, as an interim rule.

Pursuant to section 502(b) of the NGPA, the Commission invites interested persons to submit data, views and other information concerning the matters addressed in this rule. An original and 14 copies of written comments should be filed with the Commission by November 3, 1980. Interested persons may also request the opportunity for an oral presentation of their views at a public hearing. Requests for an oral hearing should be filed with the Commission by October 3, 1980. Such comments and requests should be submitted to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should reference Docket No. RM80-78. If a public hearing is held in this docket, it will be held at the above address on October 17, 1980, and will be announced October 6, 1980.

All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426 during regular business hours.

(Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301, *et seq.;* Department of Energy Organization Act, 42 U.S.C. §§ 7101, *et seq.;* E.O. 12009, 3 CFR 142 (1978))

In consideration for the foregoing, the Commission amends Part 1, Subchapter A, and Subpart B, Part 282, Subchapter I, of Chapter I, Title 18 of the *Code of Federal Regulations*, on an interim basis, as provided below, effective immediately.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,192]

45 F. R. 66784 (October 8, 1980)

18 CFR Part 284

[Docket No. RM79-34]

Transportation Certificates for Natural Gas for the Displacement of Fuel Oil

Issued: September 26, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission hereby amends its regulations to specify the treatment accorded natural gas delivered as part of a fuel oil displacement program, when the Commission establishes future pipeline curtailment plans. This amendment rescinds the action taken on August 15, 1980, which was never made effective.

EFFECTIVE DATE: September 26, 1980.

FOR FURTHER INFORMATION CONTACT:

Robert Platt, Assistant Advisory Counsel, Office of the General Counsel, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357-8457.

Robert J. Cupina, Office of Pipeline and Producer Regulations, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357-9036.

Glenn Berger, Office of the General Counsel, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357-8364.

I. Procedural History

On August 15, 1980, the Federal Energy Regulatory Commission (Commission) issued Order No. 30–D,[1] which extended through May 31, 1981, the Commission's program for authorizing transportation of natural gas to replace the consumption of fuel oil by designated end users. Prior to the issuance of Order No. 30–D, the regulations implementing the fuel oil displacement program provided in § 284.206 that volumes of natural gas transported in fuel oil displacement transactions would not be considered in future curtailment plans.[2] Order No. 30–D eliminated this provision's effect on volumes delivered after September 1, 1980.

Consolidated Edison Company of New York (Con Ed) and Public Service Electric and Gas of New Jersey (PSE&G) filed requests for a stay of the amendment to § 284.206 pending rehearing of Order No. 30–D. We granted the stay by order issued on August 29, 1980.[3] On September 5, 1980, Brooklyn Union Gas Company (Brooklyn Union) filed a petition for rehearing of the August 29, order granting the stay.

Petitions for rehearing of Order No. 30–D were filed by Consolidated Gas Supply Corporation (Con Gas), Con Ed, the Department of Energy (DOE), National Gas & Oil Corporation and Ohio Producers (Ohio Group), Orange and Rockland Utilities, Inc. (O&R), the Process Gas Consumers Group (PGCG), and PSE&G. On August 26, 1980, Congressman John D. Dingell petitioned the Commission to reconsider Order No. 30–D.

The pleadings which remain outstanding in this docket allege two grounds for error: whether the fuel oil displacement period should have been extended from September 1, 1980 to May 31, 1981, and whether the curtailment protection provisions of § 284.206 should apply during the extension. Upon consideration of these petitions, we deny rehearing on the first issue and grant rehearing on the second.

II. Extension of Order No. 30

The PGCG opposes the nine-month extension.[4] Congressman Dingell also expresses concerns and urged reconsideration of the extension.

Both PGCG and Congressman Dingell question whether adequate gas supplies exist to support the nine-month extension. The PGCG notes that some interstate pipelines project a degree of curtailment during the coming winter, and suggests that the current gas supply outlook may not justify the nine-month extension.

The Commission has been sensitive to this concern throughout the Order No. 30 program, and has established safeguards to ensure that any volumes of gas transported under the Order No. 30 program are, in fact, surplus supplies. In the case of sales by interstate pipelines who must obtain a certificate for such transactions, the presiding administrative law judge must inquire as to whether no other natural gas company seeks to purchase the gas for its own system supply.[5] In the case of sales by intrastate pipelines and local distribution companies, the appropriate state commission has the opportunity to prevent the transaction if the gas is necessary to alleviate curtailment within the state.[6] Finally, once a transaction has commenced, either the Governor of a state or the Commission may terminate the sale.[7] Given these safeguards, it is unlikely that Order No. 30 sales will be made by systems experiencing a serious threat of curtailment.

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[1] 45 FR 56046 (August 22, 1980).

[2] Order No. 30–D amended § 284.206 of the regulations to read:

> All volumes of natural gas purchased prior to September 1, 1980, by an eligible user and transported by an interstate pipeline pursuant to this subpart shall not be considered as either a natural gas supply or market in a determination of an interstate pipeline's customers' requirements for present or future allocations of natural gas during periods of natural gas curtailment.

[3] 45 FR 60418 (September 12, 1980).

[4] Order No. 30–D extended the program by amending the definition of the "fuel shortage emergency period" to extend through May 31, 1981. Despite the name of this term, the Commission does not explicitly find that a fuel shortage emergency exists during this extension period. That term is a carryover from the original rule and was retained for purposes of convenience.

[5] 18 CFR 284.206(d)(2)(i).

Instead of causing curtailment, the Commission expects that the Order No. 30 program will afford certain gas users a means of minimizing the impact of any regional curtailment which may occur this winter. Under the program, an end-user facing curtailment from traditional suppliers may purchase gas from sellers who have a temporary surplus. Thus, the program provides those end-users which might be affected by any regional shortage with the opportunity to obtain supplies from other areas.

PGCG further argues that gas supplies are a finite resource, that gas reserves and production have significantly declined over the last decade, and that the Order No. 30 program accelerates this decline because it encourages unnecessary consumption of gas.

The Natural Gas Policy Act of 1978 (NGPA) 15 U.S.C. §§ 3301–3432, attempts to reverse the decline in production and reserves by providing producers with incentives for new exploration and development. The rapid increase in natural gas supplies which has occurred since enactment of the NGPA indicates to the Commission that the downward trend has abated and that statutes and regulatory policies can significantly effect development of new natural gas reserves. The Order No. 30 program is, in fact, designed to affect gas markets so as to preserve incentives for further development of gas reserves.

Recently most interstate pipelines have been in a position to meet all their customers' requirements. The extensive take-or-pay commitments undertaken by many major interstate pipelines discourages them from contracting for new reserves. Therefore, the current softness in demand tends to discourage further exploration and development efforts.

One benefit of the Order No. 30 program has been that it has helped absorb this temporary surplus and therefore has minimized the negative effect of the surplus upon the development of new reserves. The PGCG incorrectly characterizes the extension of Order NO. 30 as a wasteful "burn-gas-to-get-gas" program which discourages conservation in order to create a market for new production. The Commission does not agree. While the Order No. 30 program does provide a market for excess supplies, the program is tailored to permit these supplies to reduce fuel oil consumption. These fuel oil users do not represent a permanent addition to the natural gas market, and many of the participating end-users had previously used natural gas prior to earlier periods of curtailment. By targeting the gas to fuel oil users, the consumption of the gas furthers the national objective of decreasing our dependence upon imported oil and oil products.

Given the need for a policy that accommodates excess current deliverability while maintaining an environment encouraging producer development of long-term supplies, the Commission has exercised its discretion to create a carefully controlled market for otherwise surplus gas supplies.

Congressman Dingell also expresses concern that Order No. 30 transactions may effectively use imported natural gas to displace less expensive residual fuel oil in many instances. Should this be the case, the nation's balance of payments would be negatively effected and the nation's imported energy dependence would not be changed.

The Commission understands and has fully considered this problem. In seeking public comment on whether to extend Order No. 30 last May, the Commission specifically addressed the issue of whether the regulations should limit the program to purchasers backing out high quality (low sulfur residual and No. 2 distillate) fuel oil. Such a limitation would have resolved Congressman Dingell's concern. However, the Commission decided not to so confine the program.

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[6] 18 CFR 284.202(b)(2).

[7] 18 CFR 284.205(d)(2) and (3).

Two factors underlie this decision. First is the fact that many pipelines are out of curtailment. Many pipelines have demonstrated excess deliverability. It therefore appears feasible for the nation to displace imported oil with domestic natural gas. If the United States' gas markets work with any rationality, pipelines with excess deliverability will reduce to as low as possible their takes of high priced imported gas. This appears to be happening. For this reason, it is unrealistic to regard imported gas as a current source of supply for Order No. 30 transactions.

However, even if a convincing showing could be made that pipelines were taking imported gas in order to facilitate Order No. 30 transactions, the Commission nonetheless might permit such gas to displace low quality fuel oil. The Commission and the Economic Regulatory Administration of the Department of Energy (ERA) would have to determine, on a case-by-case basis, whether the relative price of the imported gas supply over the oil being displaced is so excessive as to render the transaction inconsistent with the public interest. Factors such as the relatively more secure character of imported Canadian and Mexican gas supply, and the nation's relatively smaller overall dependence on imported gas as compared with oil, could warrant upon further examination paying a higher price for imported gas and using that gas to back out expensive imported residual oil.

Because imported gas and oil supply prices can change rapidly, the point raised by Congressman Dingell deserves continued examination. The Commission expects that the ERA will monitor the status of gas and oil imports with care during the remaining eight months of the Order No. 30 program. In response to the monitoring, the Commission is prepared to exercise its termination authority if conditions so warrant.

III. Curtailment Consequences

Con Ed and Con Gas allege that the amendment to § 284.206, which has the effect of limiting the curtailment protection provision to volumes delivered prior to September 1, 1980, subjects to cancellation Con Ed's outstanding contractual relationships with its suppliers of gas under Order No. 30. The concerns of Con Ed, Con Gas, and PSE&G are based upon the fact that Order No. 30 end-users have traditionally been assigned a low priority in end-use curtailment plans. If the Commission were to implement fixed base period curtailment plans in the future, which based the allocation of natural gas upon the amount of gas used during a time period when an Order No. 30 customer was using gas rather than fuel oil, Con Ed and PSE&G fear that Order No. 30 volume would be included in the curtailment data. If such short-term sales were included, then the distributor serving the Order No. 30 customer would be curtailed based upon a greater proportion of low-priority load than is in fact usually served by its system. Thus, if Order No. 30 volumes are not correctly reflected in base period data, a distributor's short-term participation in Order No. 30 might subject it to greater risk of curtailment over the life of a new curtailment plan. Con Ed and the Ohio Group also state that the rulemaking procedure did not afford adequate notice of the amendment to § 284.206, and that Order No. 30-D failed to explain adequately the reasons for the amendment.

The DOE believes that the elimination of the § 284.206 curtailment immunity provision is unwarranted and may substantially reduce the effectiveness of the program. In addition, O&R argues that the amendment to § 284.206 is inconsistent with a Federal Power Commission order which excluded O&R's short-term supplies from its curtailment profile.

In contrast, Brooklyn Union, which requested the amendment to § 284.206 in its written and oral comments, argues that the provisions of § 284.206 could be used by participants in Order No. 30 sales to the detriment of those pipeline customers who decline to participate in the program. Thus, Brooklyn Union asserts that parties would attempt to use §284.206 as a "sword" rather than a "shield" in any future curtailment plan. Brooklyn Union has noted that curtailment policy is in a state of transition and that the exact wording of § 284.206 may not be well-suited for approaches adopted in the future. Hence, Brooklyn Union fears that § 284.206 could be misapplied in the case where a distributor's low priority markets would have been included in a curtailment profile in the absence of Order No. 30 purchase. Similarly, problems could arise when a seller attributes particular supplies to Order No. 30 transactions.

Because the Commission does not wish to disturb existing contractual relationships between fuel oil users and sellers under the Order No. 30 program, § 284.206 shall be amended to apply to the remaining months of the program's duration. However, the Commission notes that the text of § 284.206 will inevitably be subject to interpretation when implementing new interstate pipeline curtailment plans. When such questions of interpretation arise, the Commission intends to prevent § 284.206 from being used to increase curtailment allocations as a result of participation in the Order No. 30 program. Thus, Brooklyn Union's concerns can be met through the careful implementation of any new curtailment plans.

IV. The Stay of §284.206

Brooklyn Union's petition for rehearing of the August 29 order granting a stay also bears on the curtailment question. Brooklyn Union alleged that the Commission erred by acting on Con Ed's request for stay prior to the time specified in § 1.9(a) for filing answers to a complaint or a petition. The Commission believes that the Con Ed or PSE&G pleadings were in the nature of motions. Since provisions of § 1.9(a) are limited to complaints and petitions, it does not apply in this case.[8] Thus, the Commission did not err in acting upon Con Ed's motion within 10 days from the time it was filed. Furthermore, given the Commission's decision to reinstitute the protections of § 284.206 to volumes delivered after September 1, 1980, Brooklyn Union's grievance is moot. Accordingly, Brooklyn Union's September 5, 1980, petition for rehearing shall be denied.

Similarly, the petition of PSE&G seeking stay of § 284.206 is moot as a result of the action taken in the August 29 order and this order.

V. Summary of Amendments and Effective Date

Subpart F of Part 284 is amended in only two respects: by correcting a clerical error in § 284.202, and by eliminating a provision in § 284.206, which was stayed and never placed into effect.

Because these amendments do not change any effective provision of the Order No. 30 program, good cause exists to waive the 30 days prior notice requirement of 5 U.S.C. § 553(d) and to make this rule effective immediately.

(Natural Gas Act, 15 U.S.C. § 717–717w; Natural Gas Policy Act of 1978, 15 U.S.C. § 3301–3432; Department of Energy Organization Act, 42 U.S.C. § 7101–7352; E.O. 12009, 42 FR 46267)

The Commission Orders:

(A) The applications for rehearing of Order No. 30–D filed by Con Ed, Con Gas, DOE, O&R, Ohio Group, and PSE&G are granted with respect to § 284.206 of the Commission's regulations.

(B) In all other respects, the petitions for rehearing are denied.

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[8] *See* 18 CFR 1.9(c).

(C) In consideration of the foregoing, Part 284 of Chapter I, Title 18, Code of Federal Regulations, is amended, as set forth below, effective immediately.

By the Commission.

Lois D. Cashell,
Acting Secretary.

[¶ 30,193]

45 F. R. 66787 (October 8, 1980)

18 CFR Part 292

[Docket No. RM79-54]

Order Granting Rehearing of Order No. 70-B and Amending Regulations

Issued: September 26, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Order granting rehearing of Order No. 70-B and amending regulations.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts an Order Granting Rehearing of Order No. 70-B. The Order amends § 292.202(n) of the Commission's rules involving small power production and cogeneration facilities. The amendment allows electric utility holding companies which have obtained an exemption from the Securities and Exchange Commission, pursuant to sections 3(a)(3) or 3(a)(5) of the Public Utility Holding Company Act, to own 100 percent of the equity of a qualifying facility.

EFFECTIVE DATE: September 26, 1980.

FOR FURTHER INFORMATION CONTACT: Adam Wenner, Office of General Counsel, 202-357-8033 or Glenn Berger, Office of General Counsel, 202-357-8364, or Michael Kessler, Office of General Counsel, 202-357-5227.

On august 28, 1980, STEAG Aktiengesellschaft (STEAG) applied for rehearing of Order No. 70-B, issued by the Federal Energy Regulatory Commission (Commission) on August 4, 1980.[1] On September 3, 1980, the American Paper Institute, Inc. (API) also applied for rehearing of Order No. 70-B. In Order No. 70-B, the Commission amended its rules to permit gas utility holding companies to own qualifying facilities. That change was accomplished by substituting the words "electric utility holding company" for the words "public utility holding company" in § 292.206(b) and § 292.207 (b)(2)(v) of the Commission's rules, and by adding a definition of "electric utility holding company" to § 292.202.[2]

In Order No. 70-B the Commission also recognized that, as a result of the above changes, certain companies which are not "primarily engaged in the generation or sale of the electric power" may nevertheless be classified as "electric utilities" or "electric utility holding companies." Such companies could not own more than 50 percent of the equity of a qualifying cogeneration or small power production facility.[3] The Commission specifically recognized that:

> Included in this category are companies which derive most of their income from non-utility operations, but which, as a result of selling some electric energy, are classified as "electric utilities" under Section 3(22) of the Federal Power Act; and public utility holding

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[1] 45 FR 52779 (August 8, 1980).

[2] *Id.*

[3] *See* § 292.206 of the Commission's rules regarding ownership criteria of cogeneration or small power production facilities.

companies which are exempt by rule or order issued by the Securities and Exchange Commission [SEC] pursuant to sections 3(a)(3), 3(a)(4), and 3(a)(5) of the Public Utility Holding company Act of 1935.[4]

Both STEAG and API contend that the definition of "electric utility holding company" added by Order No. 70–B is too restrictive and will exclude certain potential cogenerators and small power producers from obtaining qualifying status, contrary to the intent of Congress as expressed in section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA). Both companies point out that the general rule contained in § 292.206(a) of the Commission's rules which paraphrases sections 3(17)(C)(ii) and 3(18)(B)(ii) of the Federal Power Act (FPA), is that a qualifying facility "may not be owned by a person primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities)." They contend that companies which have obtained exemption from regulation as electric utility holding companies by the SEC on the grounds that they are not primarily engaged in the generation or sale of electric power should be similarly exempted from the definition of "electric utility holding company" found in § 292.202(n) of the Commission's rules.

Section 3(a)(3) of PUHCA

API suggests that the Commission allow facilities owned by persons exempt from the requirements of the Public Utility Holding Company Act (PUHCA) by reason of an exemption granted under section 3(a)(3) of that Act to obtain qualifying status. Section 3(a)(3) of PUHCA permits the SEC to grant an exemption to a holding company which is "only incidentally a holding company, being primarily engaged or interested in one or more businesses other than the business of a public utility company." [5] Since the standards under section 3(a)(3) of PUHCA and sections 3(17)(C) and 3(18)(B) of the Federal Power Act are virtually identical, API asserts that exemption under the former clearly satisfies the standard set forth in the latter.

Section 3(a)(3) of PUHCA allows the SEC to exempt any holding company from the provisions of that Act if:

> . . . such holding company is only incidentally a holding company, being primarily engaged or interested in one or more businesses other than the business of a public utility company and (A) not deriving, directly or indirectly, any material part of its income from any one or more subsidiary companies, the principal business of which is that of a public-utility company, or (B) deriving a material part of its income from one or more such subsidiary companies, if substantially all the outstanding securities of such companies are owned, directly or indirectly, by such holding company.[6]

The SEC grants holding companies an exemption under section 3(a)(3) on a case-by-case basis. Although the SEC has the authority to do so, it has not adopted a generic rule regarding this exemption. The statute, however, sets out two basic standards for granting such an exemption. These are: (a) whether the company is only incidentally a holding company, and (b) whether the company is primarily engaged in a business other than that of a public utility.[7]

Under the "incidental ownership" standard, the SEC determines whether the utility operations of the subsidiary company are functionally related to the parent company seeking exemption. An example of this type of ownership is the case where a parent company purchases power for industrial purposes from a utility subsidiary, with only surplus power being sold to others.

Under the "primarily engaged" standard, the SEC examines both the absolute amount of utility assets owned by the parent company, and also compares utility with non-utility gross revenues and assets. Although there is no fixed standard, if, for example, more than 50 percent of a company's revenues were derived from utility revenues, it is unlikely that it would qualify for an exemption. An electric utility holding company must satisfy both of these standards in order to qualify for exemption.

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[4] Order No. 70–B, 45 FR at 52779 (August 8, 1980).

[5] 15 U.S.C. § 79c(a)(3).

[6] 15 U.S.C. § 79c(a)(3).

[7] *Id.*

The present definition of an "electric utility holding company" is so broad that many industries which are classified as exempt holding companies may be discouraged from investment in cogeneration or small power production facilities. The exempt status of such a holding company is not affected by the fact that a facility owned by a subsidiary of the holding company is a qualifying facility. However, if a facility owned by the subsidiary company is not a qualifying facility, the subsidiary company could be subjected to regulation as a "public utility" under Part II of the Federal Power Act, and to State regulation of rates and financial organization. In this case the rates the subsidiary would receive for wholesale sales could be determined not on the basis of avoided costs, but rather under traditional "cost-of-service" utility regulation. This would likely result in less investment in cogeneration and small power production by exempt holding companies.

The Commission believes that a finding by the SEC that a holding company is exempt under section 3(a)(3) satisfies the standard in the Federal Power Act that an owner of a qualifying facility is "not primarily engaged in the generation or sale of electric power." The Commission believes that "incidental" holding companies are, by definition, primarily non-utility companies which, for purposes of this program, should not be treated differently from industries which are not classified as holding companies under the PUHCA.

In the preamble to Order No. 69, the Commission stated that "these rules are not intended to divest a State regulatory agency of its authority under State law to review contracts for purchases as part of its regulation of electric utilities."[8] The Commission believes that review by the State regulatory authority of the prudence of a purchase is especially appropriate when a qualifying facility owned by a subsidiary of an exempt public utility holding company provides power directly or indirectly to an electric utility which is part of the same holding company system.

Moreover, the State regulatory authorities may establish rate for purchases from existing qualifying facilities at less than avoided cost on a finding that the rate "is sufficient to encourage cogeneration or small power production."[9] Under this provision, a rate for purchases from existing facilities which obtain qualifying status could be maintained at existing levels, if the State makes the requisite finding.

Section 3(a)(5) of PUHCA

STEAG contends that the limitation on ownership of qualifying facilities established in the Commission's rules is inapplicable to holding companies which are exempt from SEC regulation under section 3(a)(5) of PUHCA. Section 3(a)(5) of PUHCA allows the SEC to exempt a holding company from regulation if it "is not, and derives no material part of its income, directly or indirectly, from any one or more subsidiary companies which are, a company or companies the principal business of which within the United States is that of a public-utility company."[10] Included in the category of companies that may obtain an exemption under section 3(a)(5) of PUHCA are domestic, as well as foreign holding companies which derive no material part of their income from subsidiary companies, the principal business of which, within the United States, is that of an electric utility.

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[8] 45 FR 12233 (February 25, 1980).

[9] Order No. 69, Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, § 292.304(b)(3).

[10] 15 U.S.C. § 79c(a)(5).

Based on the legislative history of the ownership criteria established in PURPA section 201, STEAG suggests that Congress was seeking "to preserve the authority of regulatory agencies within the United States over persons with monopoly franchises primarily engaged in the generation or sale of electric power subject to their jurisdiction." [11] The ownership restrictions on qualifying facilities for both electric utilities and their parent holding companies are based on a concern that such companies would divert scarce capital resources or convert existing jurisdictional facilities into unregulated qualifying facilities. [12]

This policy, STEAG contends, has no applicability to foreign holding companies "since they would not be diverting funds or facilities from regulated to unregulated electric utility activities within the United States." [13] STEAG contends that exclusion of electric utility holding companies which have obtained a PUHCA section 3(a)(5) exemption is contrary to the Congressional intent.

STEAG points out that "unless the intention to have a statute apply to actions occurring beyond the limits of the United States is clearly expressed or indicated by its language, purpose, subject matter or history, the presumption is that the statute is intended to have no extraterritorial effect, but to apply only to activities occurring within the territorial jurisdiction of the United States or involving United States citizens." [14] This principle applies "to a statute using general words, such as 'any' or 'all' in describing the persons or acts to which the statute applies." [15] STEAG also contends that the use of the general words "any" and "a" in the PURPA definitions of "electric utility" and qualifying cogeneration and small power production facilities should not be construed to include the generation or sale of electric power which occurs outside the territorial jurisdiction of the United States.

The Commission believes that domestic and foreign holding companies which are exempt under section 3(a)(5) of PUHCA are not "primarily engaged in the generation or sale of electric power" in the United States for the purpose of obtaining qualifying status. So long as these Companies meet the requirements of section 3(a)(5) of PUHCA they should be permitted to own qualifying cogeneration and small power production facilities.

The Commission believes that a determination by the SEC that an electric utility holding company is exempt as such under either section 3(a)(3) or 3(a)(5) of PUHCA satisfies the requirement that a qualifying facility may not be owned by a person primarily engaged in the generation or sale of electric power. Thus, the Commission believes it is appropriate to allow ownership of qualifying facilities by electric utility holding companies which have obtained an exemption as such pursuant to sections 3(a)(3) or 3(a)(5) of PUHCA.

The Commission notes that on May 19, 1980, Elizabethtown Gas Company filed a Petition for Review of Order No. 70 and of the Commission's Order on Rehearing of Order Nos. 69 and 70 in the United States Court of Appeals for the District of Columbia Circuit. On June 30, 1980, the Commission filed with the court the Certificate of Record in Lieu of Record. Under Section 313(b) of the Federal Power Act, that court has exclusive jurisdiction to modify those orders. Accordingly, this order is issued subject to the court's permission.

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[11] Application for Rehearing at 6.

[12] *See* Hearings on H.R. 6831, *et al.* Before the Subcomm. on Energy & Power of the House Comm. on Interstate and Foreign Commerce, 95th Cong., 1st Sess. 1745–47 (1977) (answer of the Federal Power Commission).

[13] Application for Rehearing at 4.

[14] 73 Am. Jur. 2d Statutes § 350.

[15] *Id.*

The Commission orders:

(A) The applications for rehearing of Order No. 70–B filed by STEAG Aktiengesellschaft on August 4, 1980, and the American Paper Institute, Inc., on September 3, 1980, are granted with respect to § 292.206 of the Commission's rules.

(B) Section 292.202(n) is amended as set forth below effective September 26, 1980.

(Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 2601 *et seq.*; Federal Power Act, as amended, 16 U.S.C. § 292 *et. seq.*; Department of Energy Organization Act, 42 U.S.C. 3 C.F.R. 142 (1978))

In consideration of the foregoing, the Commission amends Part 292 of Chapter I, Title 18, Code of Federal Regulations, as set forth below, effective September 26, 1980.

By the Commission.

Lois D. Cashell,
Acting Secretary.

[¶ 30,194]

45 F. R. 67083 (October 9, 1980)

18 CFR Parts 154 and 270

[Docket Nos. RM80–7 and RM80–6, Order No. 102]

Natural Gas; Pricing of Pipeline and Affiliate Production Under the Natural Gas Act

Issued October 3, 1980

AGENCY: Federal Energy Regulatory Commission.

ACTION: Order denying rehearing of Order No. 58 and Order No. 98 and clarifiying Order No. 98.

SUMMARY: The Commission is issuing an order denying rehearing of final rules in two dockets. These rules set out the Commission's policy regarding the pricing of pipeline, distributor and affiliate production under the Natural Gas Policy Act of 1978 (NGPA) and the Natural Gas Act (NGA).

In Order No. 58 (43 FR 60577), the Commission determnined that the NGPA maximum lawful prices do not apply to sales by pipelines or distributors of commingled volumes of purchased gas and natural gas produced by the pipeline itself. Therefore, the pricing of natural gas produced by interstate pipelines but sold in mixed volume sales remains subject to the Commission ratemaking authority under the NGA. Order No. 98 established the Commission's policy under the NGA regarding the pricing of production by interstate pipelines.

Also, the Commission is adopting an amendment to § 154.42(b)(1)(i) of the regulation promulgated in Order No. 98 (45 FR 53091), to express more clearly Commission's intent that pipeline producers subject to NGPA rate treatment would be eligible to make interim collections. Because this is a clarifying amendment, the Commission found that public notice and comment on the amendment is unnecessary.

EFFECTIVE DATE: Amendment to § 154.42(b)(1)(i) is effective October 3, 1980.

FOR FURTHER INFORMATION CONTACT:

Susan Tomasky, Office of the General Counsel, 825 North Capitol Street, N.E., Room 8111, Washington, D.C. 20426, (202) 357–8461

or

Ray Beirne, Office of Pipeline and Producer Regulation, 825 North Capitol Street NE., Room 5100C, (202) 357–9371.

Order No. 102—Order Denying Rehearing of Order No. 58 and Order No. 98 and Clarifying Order No. 98.

Issued October 3, 1980.

Before Commissioners: Charles B. Curtis, Chairman; Georgiana Sheldon, Matthew Holden, Jr., and George R. Hall. Final Rule Governing the Maximum Lawful Price for Pipeline, Distributor, or Affiliate Production

(Docket No. RM80–7); and Pricing of Pipeline and Affiliate Production under the Natural Gas Act (Docket No. RM80–6).

I. Introduction

A. *First Sales Under the NGPA.* Before the enactment of the Natural Gas Policy Act of 1978 (NGPA), section 1(b) of the Natural Gas Act (NGA) gratned jurisdiction to the Federal Energy Regulatory Commission (Commission) to establish rates for sales for resale of natural gas in interstate commerce. Natural gas companies whose sales were subject to Commision rate regulation under the NGA included independent and pipeline affiliated producers, which ordinarily produce natural gas for sale to interstate pipeline purchasers, and interstate pipelines, which transport for sale natural gas acquired from independent or affiliated producers, or produced by the pipeline itself. Jurisdiction to determine rates for producer and pipeline sales in intrastate commerce was reserved to state and local authority.

The resultant disparity between prices for producer sales in the interstate and the intrastate markets, which tended to discourage dedication of new production to interstate commerce, compelled Congress to eliminate the jurisdictional barriers to a nationwide market. The NGPA supplants the Commission's jurisdiction to set rates for independent and pipeline-affiliated producer sales of natural gas, and draws certain intrastate producers' sales into the field of federal price regulation.[1] To stimulate production, Congress devised a system of maximum lawful prices for domestically produced natural gas, embodying the incentives that Congress found were necessary to induce investment in exploration for and development of new reserves.

The NGPA maximum lawful prices were uniformly applied to "first sales" of natural gas to the new nationwide market, which is comprised of interstate and intrastate pipelines, local distribution companies, and direct sale customers. To insure that natural gas would be delivered to the market at the NGPA prices, Congress also made the wellhead prices applicable to sales preceding sales to pipelines, distributors, and direct sale customers.[2]

However, the NGPA does not terminate the jurisdiction of the Commission to regulate the rates charged for transmission and sale of gas acquired and transported by interstate pipelines. Although the statute modifies that jurisdiction in certain respects in order to facilitate coordination of the Commission's responsibilities under the NGA and NGPA,[3] Congress left substantially intact the regulatory apparatus for determining just and reasonable rates applicable to sales of gas acquired and transported by interstate pipelines.

Congress recognized that pipelines and distributors, in addition to acquiring and transporting gas for sale, also engage in production activities. It drew a distinction between a pipeline or distributor's producer or field sales, and other sales that remain subject to Commission or state jurisdiction. Section 2(21)(B) of the NGPA provides that the term first sale—

> Shall not include the sale of any volume of natural gas by any interstate pipeline, intrastate pipeline, or local distribution company, or any affiliate thereof, unless the sale is attributable to volumes of natural gas

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[1] *See* discussion *infra* at page 16.

[2] Section 2(21)(A) of the NGPA defines "first sale" as "any sale of any volume of natural gas—

(i) to any interstate pipeline or intrastate pipeline;

(ii) to any local distribution company;

(iii) to any person for use by such person;

(iv) which precedes any sale described in clauses (i), (ii), or (iii); and

(v) which precedes or follows any sale described in clauses (i), (ii), (iii), or (iv) and is defined by the Commission as a first sale in order to prevent circumvention of the maximum lawful price established under this Act.

[3] For example, section 601(c) facilitates interstate pipeline pass-through of the purchased gas cost of natural gas acquired in a first sale, by providing that a price no greater than the applicable maximum lawful price is deemed just and reasonable for purposes of determining a pipeline's cost-of-service under the NGA.

produced by such interstate pipeline, intrastate pipeline, or local distribution company, or any affiliate thereof.

In Order No. 58,[4] the Commission promulgated § 270.203 of its regulations, determining which sales of natural gas by a pipeline, local distribution company, or affiliate thereof are first sales within the meaning of section 2(21)(B) of the NGPA. Paragraph (a) of § 270.203 provides that:

> (f)or purposes of applying section 2(21)(B) of the NGPA, a sale by a pipeline of distributor is a sale of natural gas attributable to volumes of natural gas produced by such pipeline or distributor to the extent that such sale is comprised exclusively of production volumes of natural gas from identifiable wells, properties, or reservoirs which are owned by such pipeline or distributor.

This interpretation reflects the Commission's view that the purpose of section 2(21)(B) is to distinguish between pipeline and distributor sales occurring at the wellhead or in the field,[5] and sales from a pipeline's or distributor's general system supply. Wellhead or field sales clearly are sales attributable to a pipeline's or distributor's own production; sales from a pipeline's system supply are comprised of commingled volumes of purchased gas and pipeline production. Thus, the volumes are attributable to the production properties of independent producers, producing affiliates of the pipeline, and the pipeline itself. This distinction between two types of pipeline and distributor sales, embodied in § 270.203, is consistent with the language of section 2(21)(B), and with the legislative objective of coordinating the pricing scheme of Title I with the on-going jurisdiction of the Commission and state and local authorities to determine rates for sales of natural gas transported for sale by pipelines and distributors.[6]

In contrast with a pipeline that engages directly in production activities, a producing affiliate of a pipeline or distributor that is not itself a pipeline or distributor does not sell mixed volumes of natural gas. Instead, like an independent producer, a producing affiliate sells its production volumes to its affiliated pipeline or distributor, or to other purchasers. Consistent with paragraph (a) of § 270.203, § 270.203(c) treats such sales as first sales within the meaning of section 2(21)(B), because the sales are comprised wholly of volumes attributable to the affiliate's own production.[7]

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[4] Order No. 58, Final Rule Governing the Maximum Lawful Price for Pipeline, Distributor or Affiliate Production (Docket No. RM80-7, issued November 14, 1979), 43 FR 60577 (Nov. 20, 1979).

[5] Sale of natural gas by a pipeline or distributor would be a first sale if it were an off system sale, or if the pipeline committed volumes of gas from an identifiable well to a particular purchaser and subsequently withdrew equivalent volumes from system supply for sale to the purchaser. *Id., mimeo* at 4.

[6] Section 2(21)(A)(v) of the NGPA empowers that Commission to add to the statutory definition of first sale, in order to prevent circumvention of the NGPA maximum lawful prices. Therefore, certain mixed volume sales by pipeline and distributors could be denominated first sales and thus become subject to NGPA maximum lawful prices. In exercise of this authority, the Commission has provided in § 270.203(b) that in order to prevent circumvention of the maximum lawful prices established under Title I of the NGPA, the term "first sale" includes a mixed volume sale by a pipeline or distributor unless the price at which such natural gas is sold is regulated pursuant to the Natural Gas Act or is regulated by a State agency empowered by State statute to establish, modify or set aside the rate for such sale, or the Commission, on application, has determined not to treat such sale as a first sale. This rule preserves the existing division of state and federal authority over such sales, but asserts NGPA pricing jurisdiction over sales that are not subject to rate regulation in order to insure that NGPA prices will not be circumvented.

[7] Section 270.20(c) provides:

> (c) *Sales by certain affiliates.* Any sale by an affiliate of a pipeline or distributor is a first sale if such affiliate is not itself a pipeline or distributor, unless the Commission, on application, has determined not to treat such sale as a first sale. For purposes of this paragraph, the term "sale" does not include any transaction between an interstate pipeline and an affiliate thereof if such transaction would not have been treated as a sale for purposes of the Natural Gas Act.

This rule includes sales by non-producing affiliates that are not themselves pipelines or distributors, such as gatherers or other middlemen. Although sales by unaffiliated middlemen are first sales under section 2(21)(A), *see supra* note 2 and accompanying text, sales by middlemen affiliated with pipelines or distributors are excluded from first sale treatment under section 2(21)(B). Because historically these sales largely are unregulated, the Commission, by use of its authority under section 2(21)(A)(v), has denominated these sales as first sales to avoid circumvention of the NGPA maximum lawful prices.

B. *Pricing of Interstate Pipeline Production Under the NGA.* If a sale by a pipeline of its own production is not a first sale, the applicable rate is determined by the Commission pursuant to its authority under the NGA. In determining interstate pipeline rates under the NGA, the Commission values the pipeline's production volumes sold in a mixed volume sale as a component of the pipeline's cost-of-service. Prior to the NPA, the Commission had sought to provide parity of pricing treatment among independent and interstate pipeline producers by permitting a pipeline to value its production by reference to the area or nationwide rate that would have been applicable to the gas if it had been produced by an independent producer.[8] Area or nationwide rates were made applicable to natural gas produced from wells drilled after January 1, 1973, on leases acquired before October 8, 1969, and from all wells drilled on leases acquired after October 7, 1969.[9] Production from other, older wells, drilled prior to the institution of the parity pricing policy, continued to be valued on a cost-of-service basis.[10]

Also, a pipeline whose production was made subject to parity pricing treatment was permitted an opportunity to demonstrate that special circumstances existed that warranted exemption from area or nationwide rate treatment; a pipeline that demonstrated such special circumstances was permitted to value its production on a cost-of-service basis. [11] In addition, the Commission approved settlements in rate proceedings providing some form of cost-of-service treatment for certain pipelines that failed to demonstrate special circumstances, but that had demonstrated that to some extent cost-of-service treatment was necessary to encourage their expanded production programs. [12]

In Order No. 98,[13] the Commission re-examined its pricing parity policy in light of the enactment of the NGPA. The Commission found that the incentive prices established by Congress under the NGPA should be used to encourage interstate pipelines to develop additional supplies of natural gas. [14] It therefore promulgated § 154.42 of its regulations, which permits pipelines that were previously subject to area or nationwide rate treatment to value their production, for purposes of PGA passthrough, by reference to the NGPA price that would have been applicable to the gas if it had been sold in a first sale. However, the Commission found that such incentive prices should not be available for production from leases previously subject to cost-of-service treatment, reasoning that such pipelines have already enjoyed the benefits of a certain recovery of and return on the costs of production, and that their customers, who have borne the risks of this investment in the early years of exploration and development, should have an opportunity to receive the price benefits of cost-of-service treatment for gas produced as a result of the expenditures.

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[8] 18 CFR 2.66. *See* Opinion No. 568, *Pipeline Production Area Rate Proceeding (Phase I)*, 42 F.P.C. 738, *modified* 42 F.P.C. 1089 (1969), *aff'd, City of Chicago v. FPC*, 458 F. 2d 731 (D.C. Cir. 1971), *cert. denied*, 405 U.S. 1074 (1972); Opinion No. 699-H, *mimeo* at 47–50 (issued December 4, 1974), *to be published* at 52 F.P.C. 1604, 1634–35 (1974).

[9] Although the pipeline production was not acquired in a sale and no certificates were issued for the pipeline's acquisition of its own production, the Commission allowed the value for such gas, determined by reference to area or nationwide rates, to be reflected in the pipeline's semi-annual purchased gas filings and passed through to purchasers on the same basis as natural gas purchased from producers. 18 CFR 154.38(d)(4), note 1.

[10] The costs of pipeline production subject to cost-of-service treatment, along with the pipeline's other costs, is reflected in the pipeline's rate filings under section 4 of the NGA.

[11] 18 CFR 2.60(a)(4) (1980).

[12] *See, e.g.*, Kansas-Nebraska Natural Gas Company, Inc., Docket Nos. RP72-32, RP74-11, RP76-8 (issued December 7, 1976).

[13] Order No. 98, Final Rule Governing Pricing of Pipeline and Affiliate Production under the Natural Gas Act (Docket No. RM80-6, issued August 4, 1980), 45 Fed. Reg. 53091 (Aug. 11, 1980).

[14] *Id.*, *mimeo* at 10–15.

C. *Applications for Rehearing.* The Commission has received five timely applications for rehearing of Order No. 58,[15] arguing that the definition of first sale in § 270.203 contravenes the language and intent of section 2(21)(B) and other provisions of the NGPA.

On January 9, 1980, the Commission issued an Order Granting Rehearing of Order No. 58 for Purposes of Further Consideration, and subsequently determined that the issues of law and policy raised in these applications should be evaluated in concert with the Commission's final action on rehearing of Order No. 98, promulgating the rule for the pricing of interstate pipeline production under the NGA.[16] Six timely applications for rehearing of Order No. 98 were received.[17] After considering the arguments raised in the applications for rehearing of Order No. 58 and Order No. 98, the Commission is persuaded that its interpretation of section 2(21) of the NGPA is correct, and that the policy of pricing parity for interstate pipelines should be implemented. For reasons stated more fully below, the

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[15] Timely applications were filed by the Mid-Louisiana Gas Company (Mid-Louisiana), Kansas-Nebraska Natural Gas Company, Inc. (Kansas-Nebraska), Michigan Wisconsin Pipe Line Company (Michigan-Wisconsin), Consolidated Gas Supply Corporation (Consolidated) and Kentucky-West Virginia Natural Gas Company (Kentucky-West Virginia).

The Wallace Energy Corporation (Wallace) filed application for rehearing 31 days after the issuance of Order No. 58, has moved that the Commission deem the application timely filed, and has moved for a stay in the effectiveness of the rule as it applies to Wallace. We express no view on Wallace's argument that the Commission is obliged to deem its application timely filed. However, recognizing that its application was filed only one day after the closing of the period for rehearing, the Commission will treat the application as a motion for reconsideration and consider the merits of Wallace's arguments in this Order. Wallace is pursuing issues on Rehearing of Order No. 58 in two other forums before the Commission, and has now been granted interim relief by the Director of Office of Pipeline and Producer Regulation. *See,* Order of the Director, OPPR, Granting Interim Relief (Docket No. SA80-6, issued Dec. 13, 1979). We have found nothing in Wallace's petition which persuades us that Wallace is suffering irreparable injury as a result of this rule, and the stay is therefore denied. The Conecuh-Monroe Counties Gas District (Conecuh-Monroe) has replied in opposition to Wallace's application for rehearing. In accordance with 18 CFR 1.34(d), the Commission will not consider a response to an application for rehearing.

In addition Mobile Gas Service Corp., Scotch Plywood Co. of Alabama and Clarke-Mobile County Gas District filed application for rehearing of Order No. 58 on June 23, 1980; on June 28, 1980 Conecuh-Monroe Counties Gas District, Alabama filed an application for rehearing of that order. We find that these parties have shown no good cause why their application should be considered six months out of time, and therefore we are denying the applications.

[16] Order No. 98, *mimeo* at 7.

[17] Timely applications were filed by Michigan-Wisconsin, Kansas-Nebraska, Northwest Pipeline Company (Northwest), Kentucky-West Virginia, Consolidated and Arizona Electric Power Cooperative, Inc. (AEPCO). No untimely applications were filed. On September 25, the Commission granted rehearing of Order No. 98 for purposes of further consideration. (Docket No. RM80-6, issued Sept. 28, 1980)

AEPCO's application fails to specify any error in Order No. 98, and was admittedly filed only to secure AEPCO's right to participate in any administrative or judicial review of this order with respect to certain issues raised by another party in response to the Notice of Proposed Rulemaking in this docket. *See* AEPCO Motion Requesting Acceptance of Comments Out of Time and Application for Rehearing, at 2 (Docket No. RM80-6, Sept. 3, 1980). AEPCO states that its "primary concern" in this proceeding is to oppose comments made by El Paso Natural Gas Company, AEPCO's only gas supplier, in a certain issue raised in the Notice of Proposed Rulemaking in this docket. AEPCO states that it agrees with the Commission's position taken in Order No. 98 and would support that position on judicial review. Consistent with § 1.34(b) of the Commission's Rules of Practice and Procedure, and section 19(a) of the NGA, AEPCO's application is dismissed because AEPCO specifies no error in and does not claim to be aggrieved by Order No. 98.

AEPCO has also moved the Commission to modify its decision in Order No. 98 to refuse to consider out of time AEPCO's late filed comments on the proposed rule in this docket. AEPCO originally submitted comments in Docket No. RM80-6 on June 23, 1980; the comment period had closed on January 14, 1980. The Commision declined to consider these comments noting that they were not submitted prior to Commission consideration of the final rule. Order No. 98 *mimeo* at 8, n.11. AEPCO contends that on June 18, 1980, the date the Commission reached a final decision in this docket, a misunderstanding between AEPCO's counsel and Commission staff occurred, leading AEPCO to believe that the comment period had been extended until June 23, 1980. AEPCO argues that as a result of this misunderstanding, AEPCO's comments were filed too late for Commission consideration. This alleged misunderstanding, occuring on June 18, does not constitute reasonable grounds for AEPCO's failure to file during the sixty day comment period or prior to the Commission's final action. Therefore, AEPCO's motion is denied. 18 CFR 1.13(d).

Commission affirms its rules in § 270.203 and § 154.42 and denies rehearing of Order No. 58 and Order No. 98.

II. Applications for Rehearing of Order No. 58

A. *Pricing treatment of mixed volumes sales by pipeline and distributor producers.* The applications for rehearing of Order No. 58 take issue with the interpretation of section 2(21)(B) of the NGPA set forth in § 270.203(a) of the Commission's regulations. Mid-Louisiana, Kansas-Nebraska,[18] Consolidated and Kentucky-West Virginia argue that the language of section 2(21)(B) plainly entitles pipeline producers to NGPA first sale treatment for all volumes of natural gas produced by a pipeline; they believe that the only purpose of section 2(21)(B) is to insure that purchased gas will be excluded from first sale treatment. Kansas-Nebraska suggests that section 2(21)(B) was drafted as an exclusion to the first sale definition in order to distinguish the situation of pipeline and independent producers; such a distinction is necessary, it argues, because a pipeline, unlike an independent producer, sells purchased gas as well as its own production. Applicants conclude that the Commission, in promulgating § 270.203(a), has exceeded the bounds of its statutory authority by adopting of a rule that negates the language and intent of the statutorily prescribed definition of first sale [19] and unlawfully discriminates against pipeline producers.[20]

Some of these commenters also contend that the Commission's interpretation rests on the erroneous assumption that the inclusion of purchased volumes in a sale by a pipeline or distributor deprives those volumes attributable to its own production of first sale treatment. They argue that the Commission can determine what portion of a pipeline's general system supply is attributable to its own production and what portion is composed of purchased gas, and accord first sale treatment to the pipeline produced portion of the sale.

We cannot agree that the plain meaning of section 2(21)(B) guarantees a pipeline the right to collect a first sale price for all volumes of natural gas produced by that pipeline or distributor without regard to the type of transaction or the manner in which the gas is transferred. Section 2(21)(B) speaks in terms of sales, not volumes of natural gas, and excludes a pipeline or distributor sale from first sale treatment "unless such sale is attributable to volumes of natural gas produced by such interstate pipeline, intrastate pipeline or local distribution company, or any affiliate thereof." By the terms of the statute, first sale treatment of a sale made by a pipeline or distributor depends upon the source of the natural gas volumes that comprise the sale. If the source of the volumes that comprise the sale cannot be identified as the pipeline's or distributor's own wells, properties, or reservoirs, the Commission will not accord first sale treatment to the sale. A sale comprised of commingled volumes of purchased gas and pipeline production does not meet this test.

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[18] The application of Michigan-Wisconsin is identical to the application of Kansas-Nebraska. Any description of the views of Kansas-Nebraska also describes the views of Michigan-Wisconsin.

[19] Consistent with their view of the attribution rule Kentucky-West Virginia, Mid-Louisiana and Consolidated argue that paragraphs (b) and (c) of § 270.203 (which extend first sale treatment in certain circumstances to sales of pipeline and affiliate production) accomplish the right result for the wrong reason. These applicants believe that the Commission has no discretion to denominate as first sales the sales described in § 270.203 (b) and (c), because such sales are in fact first sales by statutory prescription. By using its discretionary authority under section 2(21)(A)(v), to denominate these sales as mixed sales, the Commission, they claim, purports unlawfully to retain the discretion to deny such gas first sale treatment at a later time.

[20] Kansas-Nebraska contends that they have been denied equal protection under the law by the Commission's adoption of § 270.203, because the rule discriminates against pipeline producers *viz-a-viz* other producers. Kentucky-West Virginia argues that they have been denied equal protection *viz-a-viz* pipeline producers with producing affiliates because eligibility for first sale treatment depends solely on corporate form. Also, Kansas-Nebraska argues that the passage of Title I and section 2(21)(B) of the NGPA vested in pipeline producers a "property right" that has been deprived them without due process of law.

We find no merit in these arguments. An administrative and legislative classification in economic regulation does not violate the principles of equal protection so long as the classification is rationally related to some legitimate legislative purpose. *United States Dept. of Agriculture* v. *Moreno*, 413 U.S. 528, 533 (1973); *Community-Service Broadcast of Mid-America, Inc.* v. *F.C.C.* 593 F. 2d 1102, 1122 (D.C. Cir. 1978).

As the foregoing discussion fully demonstrates, distinguishing between wellhead sales and mixed volumes sales is clearly related to the legislative goal of Title I to provide price incentives to encourage production.

Similarly, the due process clause is broadly tolerant of economic price controls. Such economic regulation does not violate the Constitutional guarantees against deprivation of property without due process of law, so long as the regulation is not arbitrary and does not result in confiscation. *E.g.*, *Federal Power Commission* v. *Natural Gas Pipeline Co. of America*, 315 U.S. 575, 589–90 (1942). Under the rule of section 2(21)(B) and § 270.203 rates for sales by an interstate pipeline, such as Kansas-Nebraska, will be just and reasonable rates determined according to the Constitutionally sound standards established under the NGA.

We do not agree with Kansas-Nebraska that the purpose of section 2(21)(B) is simply to distinguish between independent and pipeline producers. By excepting pipeline, distributor and affiliate production from the general definition of first sale contained in section 2(21)(A), the NGPA distinguishes between pipeline sales from the general system supply and pipeline sales that occur at the wellhead. This distinction is necessary to preserve the existing division between state and federal pipeline regulation and to preserve the NGA cost-of-service ratemaking scheme for sales from an interstate pipeline's general system supply.

As we noted in Order No. 58, the interpretation of section 2(21)(B) advocated by these commenters would result in the uniform application of first sale maximum lawful prices to all mixed volume retail sales made by pipelines and distributors. As a result, rates for retail sales by intrastate pipelines and local distribution companies could not exceed the applicable maximum lawful prices, a result that would preempt the retail ratemaking jurisdiction of state and local agencies. The Commission finds no evidence in 2(21)(B) or in any other provision of the statute that suggests that Congress intended to require the Commission to expand the field of federal ratemaking authority to include all mixed volume retail sales by intrastate pipelines or local distribution companies, the regulation of which has been the historic preserve of the states.

Furthermore, the interpretation espoused by these commenters assumes that the NGPA contemplates a substantial reworking of the Commission's traditional methods for determining an interstate pipeline's cost-of-service. A seller whose sale qualifies as a first sale is entitled to collect a price for that gas no greater than the applicable maximum lawful price plus any allowance for severance taxes and production related costs permitted by the Commission under section 110 of the NGPA. In seeking to determine a rate for a mixed volume sale that would provide for recovery of such costs, the Commission would be forced to discard the complex framework of statutory standards and case law precedent developed under the NGA for purposes of determining the costs of transporting its sales volumes. Rather than establishing an NGA just and reasonable rate on the basis of the pipeline's cost-of-service, the Commission would determine under its regulations implementing section 110 the costs in excess of the first sale price that a pipeline may recover to compensate it for the transportation and other costs associated with the delivery of its mixed volume sales to its purchasers.

To grant first sale treatment only to an allocable portion of an interstate pipeline's mixed volume sale cures this problem only with respect to the volumes that are allocable to purchased gas. The pipeline would recover the costs associated with the delivery of purchased gas on a traditional cost-of-service basis, permitting the recovery of all costs prudently incurred in accordance with the Commission's regulations. However, for those volumes allocable to pipeline production, the pipeline would be limited to the recovery of amounts available under section 110.[21]

With regard to intrastate pipelines, if the Commission were to accord first sale treatment to some portion of an intrastate pipeline sale, the Commission would be able to determine the section 110 allowance associated with the pipeline production, but would lack jurisdiction to scrutinize the recovery of costs associated with transportation of purchased gas. To the extent that costs allocable to pipeline production were also recovered in the price set by state or local authority, the NGPA maximum lawful price applicable to the pipeline production would be circumvented.

B. *Imputation of a Sale at the Wellhead.* Recognizing the difficulties of according first sale treatment to mixed volume sales, Kentucky-West Virginia, Kansas-Nebraska, Mid-Louisiana and Consolidated urge the Commission to impute a sale at the point at which the pipeline takes its production into its general system supply. Consolidated argues that the word "attributable" means "imputable" and, therefore, that the Commission must impute a sale at the wellhead in order to assure a pipeline first sale treatment for all volumes of its own production. Kentucky-West Virginia, Kansas-Nebraska and Consolidated point out that the statement of managers accompanying the NGPA conference report makes clear that the Commission's general rulemaking authority under section 501 of the NGPA includes the power to "establish rules applicable to intracorporate transactions under the first sale definition." [22] They argue that this language was intended to confer upon the Commission the authority to fully effectuate what they believe to be Congress' intent to accord first sale treatment to some portion of each mixed volume sale.

Mid-Louisiana contends that the delivery into the pipeline of its own production is a transfer for value, and thus meets the definition of "sale" under section 2(20) of the NGPA. Therefore, it argues that the Commission could accord first sale treatment to that intracorporation transaction by exercising its authority under section 2(21)(A)(v) to define that "sale" as a first sale.

The Commission acknowledges its authority under section 501 to impute a sale at the wellhead and thereby to accord first sale treatment to pipeline production. However, we see no mandate implicit in the definition of first sale that requires us to exercise this general authority to any specific end. We believe that the language chosen by the conference managers is clearly designed to delegate to the Commission the discretion to define the term first sale as it may apply to intracorporate transactions.[23]

In its adminstration of the NGA, the Commission has not treated as a sale the transfer of pipeline produced gas into the transmission system of that pipeline. No contracts govern that transfer; no certificates under the NGA have been issued or were required for that transfer. The proper implementation of the NGPA, which only minimally disturbs the Commission's rules of law that govern pipeline ratemaking under the NGA, does not as a practical matter compel us to vary that policy.

To the contrary, we believe that such an interpretation of the term sale would prove difficult to reconcile

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[21] Also, such an allocation would impose an enormous adminstrative burden upon interstate pipelines and the Commission. The Commission would be required to distinguish scrupulously between costs associated with purchased gas and those associated with pipeline production, so that each could be evaluated under the differing regulatory standards of the section 110 regulations and the NGA regulations. The Commission cannot easily assume, without some supporting evidence, that Congress intended to increase so substantially the regulatory burdens of determining the cost-of-service for pipeline producers.

[22] *Citing* H. Rep. No. 95–1752, 95th Cong., 2d Sess. 118 (1978). The Joint Statement provides that "(t)he Commission may define terms, prescribe the forms of reports, and prescribe effective dates for rules and regulations. For instance, the Commission may define terms such as 'transfer for value' used in the definition of first sale; it may also establish rules applicable to intracorporate transactions under the first sale definition."

administratively with certain provisions of the NGPA. For example, the maximum lawful price under section 104 assumes the existence of a just and resonable rate applicable to the sale of natural gas prior to the enactment of the NGPA. However, because the pipeline's intracorporate transfer was not a sale under the NGA, there was no just and reasonable rate applicable to that transfer. Also, the provisions of section 315, governing the duration of contracts, bona fide offers, and right of first refusal depend upon the existence of a contract for their applicability and effect. These provisions, which provide purchasers of gas from independent producers with some assurances of continued supply, are inapplicable to a pipeline that "sells" natural gas in a first sale to itself. Absent the constraints of section 315, and the requirement of abandonment authorization that would be inapplicable to gas sold in a first sale, the pipeline's purchasers would have no continuing obligation to offer its purchasers a continued supply of gas from its production properties.

To the extent that this provision and other provisions of the NGPA are conceptually dependent upon the existence of a sale, contract or certificate, the Commission would be required to devise other means by which to insure proper implementation of the statute. We have concluded that the regulation and enforcement of rates for sales of pipeline production should not depend on an event that is recorded solely on the books and records of the pipeline and that occurs without contract, bargaining, or certification. We decline, therefore, to exercise our discretion in this manner.

C. *Arguments Based on Other Provisions of the NGPA.* Several applicants argue that other provisions of the NGPA are consistent with their view of section 2(21)(B). Kentucky-West Virginia and Consolidated maintain that the incremental pricing passthrough provisions demonstrate that Congress intended all pipeline production to be accorded first sale treatment. Section 203(b) provides, in relevant part:

> **(b) First Sale Acquisition Costs.—(1) *General Rule*—For purposes of this section, the first sale acquisition cost of natural gas is—**
>
> **(A) the price paid, per million Btu's, in any first sale of such natural gas, in the case of any natural gas produced in the United States and acquired in such first sale; and**
>
> **(B) the price paid for such natural gas, per million Btu's, at the point of entry to the United States, in the case of natural gas or liquefied natural gas imported into the United States.**
>
> * * * *
>
> **(2) *Interstate Pipeline Production.*—For purposes of this section, in the case of any natural gas produced by any interstate pipeline or any affiliate of such pipeline the first sale acquisition cost of such natural gas shall be determined in accordance with rules prescribed by the Commission.**
>
> * * * *

The applicants contend that use of the phrase "first sale acquisition cost" indicates that Congress intended the pipeline's "acquisition" of its own production to be a first sale.

While we understand that these words, isolated from their context, may appear to imply that a true first sale within the meaning of section 2(21)(B) has occurred, we believe that the language of the section as a whole leads to the opposite conclusion. Clause (1)(A) of subsection (b) sets out the general rule permitting passthrough of first sale acquisition costs equal to the "price paid——in any first sale of such natural gas, in the case of any natural gas produced in the United States and acquired in such first sale." In contrast, clause (2) sets out a special rule applicable to interstate pipeline production to provide for passthrough of first sale acquisition costs of such natural gas "determined in accordance with rules prescribed by the Commission." The provision for pipeline production differs notably from the general rule in that it omits any reference to "price paid" and does not indicate that such gas will be "acquired

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[illegible] *See* discussion *infra* page 21–23.

in a first sale." Had Congress intended to mandate that "first sale" include all deliveries of a pipeline's production from the wellhead to its transportation system, it would have been unnecessary to create a separate rule under section 203(b)(2) for pipeline production that expressly contemplates that the acquisition cost of a pipeline's own production will be set by order or rule of the Commission.

Consolidated argues that the Commission's assertion of NGA jurisdiction over certain categories of pipeline production violates section 601 of the NGPA. Consolidated contends that the effect of section 601(a)(1)(A) is to terminate the Commission's jurisdiction with respect to any natural gas that was not committed or dedicated to interstate commerce on the effective date of the NGPA. Furthermore, it points out, section 601(a)(1)(B) terminates the Commission's jurisdiction under the NGA over committed or dedicated natural gas that qualifies for an incentive price under section 102(c), 103(c), or 107(c)(1), (2), (3) or (4). On the basis of this language, Consolidated reasons that the Commission's NGA jurisdiction has been superseded, and that a pipeline should be permitted to collect NGPA prices for all volumes of its own production.[24]

We agree that section 601(a)(1)(A) provides that NGA jurisdiction of gas not previously committed or dedicated to interstate commerce does not survive the NGPA "solely by reason of any first sale of that gas," and concede that section 601 terminates NGA jurisdiction over committed or dedicated gas that qualifies for a maximum lawful price under section 102(c), 103(c), or 107(c)(1), (2), (3) or (4). We note, however, that the scope of each of these provisions in section 601 depends upon the definition of the term first sale, and that neither provision speaks to the question of what types of sales are first sales. Thus, while we acknowledge that section 601 modifies the Commission's NGA jurisdiction with regard to gas sold in first sales, we find nothing in that section that indicates that a mixed volumes sale is a first sale for purposes of section 601 and the NGPA as a whole.

D. *First Sale Treatment of Sales by Affiliates.* Wallace Energy Corporation (Wallace) objects to the affiliate rule of § 270.203(c). First, it argues that Congress did not intend to empower the Commission to apply NGPA maximum lawful prices to sales other than wellhead sales. Wallace points out that it is a "paper company" that engages in no production and that has never before been subject to federal regulatory authority. In addition, Wallace contends that the Commission has unconstitutionally extended first sale treatment to sales "without any arguable relationship to interstate commerce." It submits that although producer sales have an impact on interstate commerce, Wallace's activities occur wholly within the state of Alabama.

We are not persuaded that the Commission has exceeded its authority under section 2(21)(A)(v). Clearly, as Wallace submits, the underlying purpose of Title I was to provide price incentives for producers and to impose some measure of regularity upon producer sales to the interstate and intrastate gas markets. However, Congress was also aware that middlemen could be used to circumvent price ceilings made applicable only to producers, and that the economic benefits of a systematic pricing scheme would be undercut by any circumvention.[25] In our view, our exercise of the Commission's authority under section 2(21)(A)(v) to treat such sales as first sales implements the express purpose of that authority to prevent circumvention of NGPA maximum lawful prices.

Wallace's contention that the Commission is without constitutional authority to regulate its wholly intrastate transactions ignores the body of constitutional law that defines the federal government's authority under the commerce clause. An act of Congress that reaches any generic category of local activity is a legitimate exercise of the commerce power if the activity has a substantial economic effect on interstate commerce. The fact that Wallace may itself have minimal impact on interstate commerce does not remove it from the scope of regulation where its activity, combined with that of other similarly situated middlemen, has a significant impact on interstate commerce.[26] Clearly, Congress was within its constitutional power to authorize the Commission to accord first sale treatment to certain wholly intrastate transactions. The Commission's proper exercise of such authority is equally free of constitutional infirmity.

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[24] See also Consolidated's Application for Rehearing of Order No. 98 (docket No. RM80-6, filed Sept. 3, 1980).

[25] See discussion *supra* note 7.

All other arguments raised in these applications have been addressed in Order No. 58, or in this Order.

III. Rehearing of Order No. 98

A. *Authority to Establish Rates for Pipeline Production Under the NGA.* Arguments raised on rehearing of Order No. 98, which sets out the Commission's policy regarding pricing of interstate pipeline production under the NGA, concern primarily the question whether the Commission's jurisdiction to establish such a policy survives the enactment of the NGPA.

Michigan-Wisconsin, Consolidated, Kansas-Nebraska and Kentucky West Virginia object to Order No. 98 as an unlawful assertion of Commission jurisdiction over wellhead prices for pipeline production. They advert to, and incorporate by reference, their applications for rehearing of Order No. 58, in which they argue that the Commission has improperly interpreted section 2(21)(B) of the NGPA to deprive most pipeline production of first sale treatment, thereby excluding such production from eligibility for NGPA maximum lawful prices. They believe that interstate pipelines as a matter of right are entitled to NGPA maximum lawful prices, and, therefore, that the Commission's attempt to assert NGA authority to regulate the price of pipeline production is unlawful.

The arguments are but corollaries to the arguments raised on rehearing of Order No. 58, which the Commission has fully addressed in the foregoing discussion. We remain convinced that the language and intent of section 2(21)(B) does not require the Commission to treat mixed volume sales by pipelines and distributors as first sales.[27] Section 2(21)(B) preserves the Commission's authority under the NGA to regulate such sales made by interstate pipelines, and serves as the jurisdictional predicate for the Commission's implementation of its parity of pricing policy.

B. *Exclusion from NGPA Rate Treatment of Natural Gas That Has Ever Been Subject to Cost-of-Service Treatment.* Two applicants object to the Commission's decision to extend NGPA rate treatment only to natural gas produced from leases that have never been subject to cost-of-service treatment. Kentucky West Virginia and Kansas-Nebraska argue that the Commission erred in its assumption that pipelines whose production has been valued on a cost-of-service basis have recouped their costs and gained substantial benefits from cost-of-service treatment.

Kentucky West Virginia does not agree with the Commission's view that investment costs of old production have necessarily been recouped, and claims that there is no evidence in the record that supports the Commission's conclusion. Kentucky West Virginia also alleges that the cost-of-service exclusion violates the pipeline's right to collect incentive prices for its high cost production and thwarts the Commission's own policy to provide incentives for production of natural gas found in tight formations. Kansas-Nebraska points to Commission precedent in support of its view that a pipeline that has at some time utilized cost-of-service pricing for its own production has not necessarily realized a greater return, as compared to the return it would have realized under area or nationwide rate treatment.[28]

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[26] E.g., *Maryland* v. *Wirtz*, 392 U.S. 183, 193, 196 n.27 (1968).

[27] As noted above, the Commission may, in its discretion, treat such sales as first sales, to prevent circumvention of the NGPA maximum lawful prices. *See supra* note 6; § 270.203(b).

The Commission is not persuaded by these arguments. Kentucky West Virginia's challenge to the Commission's position ignores the essential characteristic of cost-of-service treatment: a pipeline whose production is valued on a cost-of-service basis will receive a rate that, over time, provides for the recovery of all prudently incurred costs plus a reasonable return on investment. In the case of production from leases that have received cost-of-service treatment, the pipeline is able to recover the cost of acquiring leases, drilling unsuccessful and successful wells, and producing the reserves, including the opportunity to earn a reasonable return. Any new production from leases that will remain on cost-of-service treatment, including production from tight formations, will also be valued at a rate that will return to the pipeline producer its costs, plus a reasonable return on investment.

In response to Kansas-Nebraska, the Commission emphasizes that the benefits of cost-of-service treatment is not that a pipeline is certain to receive greater revenues than it would under area or nationwide rate treatment, although that is often the case. Cost-of-service treatment permits the pipeline producer to invest in exploration and production activities while passing on the costs and risks of that investment to its purchasers. In exchange for assuming the risks of investment, purchasers receive the benefits of additional supplies of natural gas at a rate no higher than the pipeline's costs plus a reasonable return on investment. To vary this policy now would deprive these purchasers of price benefits they should receive in exchange for assuming the risk of a pipeline's production ventures.

Kentucky West Virginia also argues that although the Commission claims that the cost-of-service exclusion is premised on the need for equitable treatment among independent and pipeline producers, its policy of "limited parity" achieves inequitable results. It contends that the Commission has varied from its prior practice by distinguishing between producing pipelines and pipelines with producing affiliates, providing NGPA rates in all cases for the latter and, in the case of the former, denying parity of treatment for substantial volumes of natural gas because the gas previously has been subject to cost-of-service treatment. Also, Kentucky West Virginia maintains that the Commission's parity policy is inequitable insofar as it provides NGPA rate treatment for wells drilled after December 31, 1972, on leases acquired before October 8, 1969, but denies parity to wells drilled before January 1, 1973 on the same leases.

The Commission finds no merit in these arguments. Sales of gas by production affiliates of pipelines or distributors (that are not themselves pipelines or distributors) are subject to NGPA maximum lawful prices because such sales are first sales within the meaning of section 2(21)(B) of the NGPA. This is consistent with the treatment accorded such sales under prior practice: under the NGA, transactions between producing affiliates and interstate pipelines were accomplished in the same manner as sales by independent producers, pursuant to contracts and certificates.[29] However, the Commission has exercised its authority under the NGA to value pipeline production for purposes of computing a pipeline's cost-of-service so as to permit parity with independent and pipeline-affiliated producers where appropriate. Thus, the distinction drawn between pipeline affiliates and pipeline producters is based on the allocation of jurisdiction over sales by these entities implied in section 2(21)(B).

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[28] *Citing* Natural Fuel Gas Supply Corp. (Docket Nos. RP76–96 and RP77–57, issued Nov. 14, 1978) *adopted by Commission*, Opinion No. 58 (issued August 6, 1974);

[29] Section 270.203(a) provides that in according first sale treatment to sales by affiliates of pipelines or distributors, "'sale' does not include any transaction between an interstate pipeline and an affiliate thereof, if such transaction would not have been treated as a sale for purposes of the Natural Gas Act."

In crafting this parity of pricing policy to provide necessary incentives to pipeline producers, the Commission weighed the interests of such pipelines and their purchasers, and determined it was necessary to preserve the price benefits guaranteed to purchasers of production subject to cost-of-service treatment in exchange for assuming the risks of the pipeline's production efforts. The distinction between wells drilled before and after January 1, 1973, on leases acquired before October 8, 1969, represents the distinctions drawn by the Commission when the area and nationwide rates were first applied prospectively to new pipeline production.[29] The continuation of the distinction effectuates the Commission's intent to continue parity of pricing treatment for pipeline production previously subject to area or nationwide rate treatment, *i.e.* production for which pipelines themselves have assumed the risk.

C. *Applicability of the Cost-of-Service Exclusion to Natural Gas That Has Been Subject to Cost-of-Service Treatment as a Result of a Settlement.* In addition to raising a general argument against the cost-of-service exclusion, Kansas-Nebraska raises objections to the provisions of the regulation that continue cost-of-service treatment. It argues that a pipeline granted cost-of-service treatment for pipeline production subject to such treatment by the terms of a settlement. Kansas-Nebraska contends that a finding on the merits of special circumstances under § 2.66(a)(4) is not equivalent to a settlement agreement that provides for cost-of-service treatment upon a finding of special circumstances has bargained for on-going cost-of-service treatment in exchange for the opportunity to pass through its risks. This, it reasons, is distinguishable from the situation of a pipeline that negotiates a settlement to resolve a limited number of issues for a specified period of time.[31] Kansas-Nebraska argues, based on Commission precedent, that the Commission may not rely on the terms of a settlement in any future rate proceeding to achieve results that a pipeline had not bargained for in the settlement.[32]

Although we agree that the provisions of a settlement do not bind the parties beyond the term of that settlement, Kansas-Nebraska errs in its conclusion that the terms of a settlement constrain the Commission's authority to determine the scope of applicability of its parity policy. The Commission's decision to deny NGPA rate treatment for gas valued on a cost-of-service basis is not only an attempt to enforce a bargain made by pipeline producers that obtained cost-of-service treatment under the special circumstances provisions.

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[29] In Opinion No. 568, the FPC initiated the parity pricing policy under which gas produced by a pipeline or its affiliates from leases acquired after October 1, 1969, and taken into the pipeline's own system would be valued by reference to the just and reasonable area rate established for sales by independent producers in the same area. *Pipeline Production Area Rate Proceeding*, Opinion No. 568–A, supra note 8, 42 F.P.C. at 1091. In opinion No. 699–H, *mimeo* at 47–50, the FPC reaffirmed its decision that pipeline production from pre-October 8, 1969 leases should continue to be priced on a cost-of-service basis, but concluded that pipeline production from wells drilled on or after January 1, 1973, should be valued at nationwide rates regardless of the date the lease was acquired.

[31] Kansas-Nebraska submits that in its particular case of the Commission had rejected its attempt to show special circumstances, but subsequently approved a settlement permitting cost-of-service treatment for all of its production that otherwise would have been subject to area or nationwide rate treatment. In Kansas-Nebraska's view, the relevant provisions of that settlement make clear that it was required to file on a cost-of-service basis only in the next subsequent rate proceeding, that the settlement represented a negotiated dollar amount, and that the use of cost-of-service methodology did not imply that any party had approved or consented to any ratemaking principle or theory of allocation.

[32] *Citing Mobile Oil Corp.* v. *FPC*, 570 F.2d 1021 (D.C. Cir. 1978); *Texas Gas Transmission Corp.* v. *FPC*, 441 F.2d 139 (6th Cir. 1971).

Our decision also rests upon our assessment that the inherent benefits of cost-of-service treatment, *i.e.* the pipeline's opportunity to pass on the risks of its production programs to its purchasers, requires us to preserve the corresponding benefits that should inure to the pipeline's purchasers. Thus where a pipeline has passed on to its purchasers the risks and costs of acquiring, exploring and developing certain leases, purchasers should be entitled to purchase the gas from those leases on a cost-of-service basis.

D. *Termination of Special Circumstances.* Northwest Pipeline Corporation (Northwest) protests the Commission's decision to deny a pipeline producer subject to NGPA rate treatment the opportunity to seek cost-of-service treatment on the basis of a showing of special circumstances. Northwest noted that in Order No. 568 the Commission encouraged pipeline producers to reinvest amounts in excess of the costs of production collected under area or nationwide rates; Northwest claims that it did reinvest its excess income with the expectation that it could attempt to show special circumstances if the costs associated with that investment proved to be too high. It therefore argues that by eliminating the special circumstances program the Commission has undermined Northwest's investment decisions.

Northwest points out that it has special overriding royalty contracts that provide for royalty payments computed on the basis of a commodity value formula. It reasons that the advent of natural gas deregulation would make these payments very high. Although the Commission has indicated that pipeline producers may be able to address such problems by seeking special relief, Northwest finds that the proposed special relief rule is not appropriate for its purposes.

First Northwest points out that the scope of the proposed special relief rule does not as yet include pipeline producers,[33] and does not specifically provide for the recovery of overriding royalty payments as an operating and maintenance expense. Northwest finds unwieldy the requirement that applications for special relief rates to cover on-going operating and maintenance expense must be submitted on a well by well basis, and believes that the proposed ceiling for special relief may prove to be too low to permit Northwest to recover the expense of its royalty payments. Moreover, Northwest argues, the Commission should not terminate the special circumstances program prior to establishing procedures for special relief. Northwest therefore urges the Commission to restore the special circumstances program so that Northwest would not be required to value its production "at confiscatory levels."

The Commission is not persuaded that the special circumstances program should be reinstated. First, Northwest correctly argues that the purpose of the special circumstances program was to encourage additional pipeline investment in drilling programs that would lead to the development of new reserves. However, the Commission found in Order No. 98 that the NGPA incentive prices were sufficient to induce future drilling efforts of pipeline producers. Furthermore, pipelines that in the past have undertaken new investment were not guaranteed cost-of-service treatment under the special circumstances program; the Commission has consistently found that the fact that a pipeline's costs exceed its revenues is not sufficient to demonstrate special circumstances warranting cost-of-service treatment.[34] Thus, no pipeline that had not been granted special circumstances undertook new investment with a guarantee that it would subsequently receive cost-of-service treatment if the costs associated with the investment proved to be too high.

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[33] The Commission asked for comments on this issue in the Notice of Proposed Rulemaking for Procedures Governing Applications for Special Relief (Docket No. RM79-67, issued May 9, 1980).

[34] Order No. 98, *mimeo* at 9, n. 19.

Also, we note that the overriding royalty payments by Northwest are not investment costs. To the extent that special rate treatment would be available to cover such expenses, it would be through application for special relief for a rate covering such payments as operating and maintenance expense. The Commission will address issues related to the scope of the special relief rulemaking in the final rule in that docket.

E. *Commission Authority to Prevent Corporate Restructuring to Avoid Cost-of-Service Treatment.* Kentucky West Virginia and Consolidate take issue with the language in Order No. 98 indicating the Commission's intent to use its authority under section 7 of the NGA to prevent a pipeline from spinning off production properties to an affiliate in order to obtain first sale treatment for volumes produced by the affiliate from those properties. Both applicants contend that the Commission lacks authority under the NGA to prevent the transfer of undeveloped leases.[35]

Consolidated submits that section 601(a) terminates the Commission's jurisdiction under the NGA over natural gas that was not committed or dedicated to interstate commerce on November 8, 1978, as well as any natural gas that, although committed or dedicated to interstate commerce on November 8, 1978, qualifies under section 102(c), 103(c), or 107(c)(1)–(4) of the NGPA. Thus, it argues, the Commission is without authority to scrutinize abandonment under section 7(b) of the NGA with respect to such natural gas.

Kentucky West Virginia points out that section 601(c) of the NGPA provides that the Commission may not deny, or condition the grant of, any certificate under section 7 of the NGA based upon the amount paid in any sale of natural gas, if such amount is deemed to be just and reasonable under subsection (b) of section 601. It reasons, therefore, that the Commission plainly is without authority to condition a transfer of leases to an affiliate so as to require cost-of-service pricing by the affiliate.

The Commission does not agree that it is without authority under the NGA to prevent a pipeline from circumventing the cost-of-service exclusion by corporate restructuring. As noted above, the provisions of section 601 of the NGPA constrain the Commission's authority with regard to natural gas sold in first sales. We therefore cannot concede that these provisions circumscribe the Commission's authority with regard to natural gas that remains subject to the Commission pricing jurisdiction under the NGA. Moreover, any jurisdictional challenges to the Commission's use of its authorities under the NGA to prevent circumvention of this rule by corporate restructuring are collateral to issues pertaining to the validity of this rulemaking. The Commission will therefore address such challenges in a more appropriate forum.

III. Clarification of Order No. 98

Since the issuance of Order No. 98, the Commission has received several inquiries regarding the eligibility of pipeline producers subject to NGPA rate treatment pursuant to § 154.42(b)(1) to make interin collections under Part 273 of Subchapter H. Under Part 273, a seller that has filed for a determination of eligibility to collect an incentive price under certain sections of Title I of the NGPA may collect that price on an interim basis prior to final determination that the well is eligible for such a price.

The Commission did not intend to preclude pipelines subject to NGPA rate treatment from making interim collections under Subchapter H. The Commission intended that the reference to Subchapter H in § 154.42(b)(3) imply this authority. In view of the confusion expressed on this point, we are clarifying § 154.42(b)(1) by expressly referencing the authority under Part 273 for such collections.

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[35] *Citing Federal Power Commission v. Panhandle Eastern Pipeline Co.*, 337 U.S. 498 (1949).

Because this amendment effects no substantive change in the rule but is necessary for proper implementation of the rule, the Commission finds that public notice and comment is unnecessary. For the same reasons, the amendment is being made effective October 3, 1980.

***The Commission Orders:* 1. Applications for rehearing timely filed of Order No. 58 and Order No. 98 are denied;**

2. The motion of Wallace Energy Corporation that its application for rehearing of Order No. 58 be deemed timely filed is denied;

3. The late filed application for rehearing of Wallace Energy Corporation is deemed a motion for reconsideration, and is denied;

4. The motion for stay of the effectiveness of Order No. 58 with respect to Wallace Energy Corporation is denied;

5. Late filed applications for rehearing of Order No. 58 by the Conecuh-Monroe Counties Gas District and Mobile Counties Services Corporation, Scotch Plywood Company of Alabama and Clarke-Mobile County Gas District, Alabama are dismissed;

6. Response of Conecuh-Monroe Counties Gas District to the Application of Rehearing of Order No. 58 of Wallace Energy Corporation is dismissed;

7. Application for Rehearing of Order No. 98 of Arizona Electric Power Cooperative, Inc. and the City of Willcox, Arizona is dismissed, for failure to specify error in that order;

8. The motion of Arizona Electric Power Cooperative, Inc. and the City of Willcox, Arizona to modify the Commission's decision in Order No. 98 to consider untimely filed comments is denied.

9. Order No. 98 is clarified by amending § 154.42(b)(1)(i) of the Commission's regulations as set forth above, effective October 3, 1980.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301 *et seq.;* Natural Gas Act, as amended, 15 U.S.C. 717, *et seq.;* Department of Energy Organization Act, 42 U.S.C. 7107 *et seq.;* Exec. Order No. 12009, 42 FR 46267)

In consideration of the foregoing, Part 154 of Subchapter E, Chapter I, Title 18, Code of Federal Regulations is amended as set forth below, effective October 3, 1980.

By the Commission.

Lois D. Cashell,
Acting Secretary.

[¶ 30,195]

45 F. R. 67276 (October 9, 1980)

18 CFR Part 282

[Docket No. RM80-75]

Agricultural Uses Exemption; Interim Rule Amending Commission's Regulations Under the Natural Gas Policy Act of 1978

October 6, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Interim rule.

SUMMARY: This rule amends § 282.202(a)(1) of the Federal Energy Regulatory Commission's regulations implementing the Natural Gas Policy Act of 1978 (NGPA). The rule as currently in effect provides that the term "agricultural use" means, *inter alia,* any use of natural gas which is certified by the Secretary of Agriculture under 7 CFR 2900.3 as an "essential agricultural use" pursuant to section 401(c) of the NGPA. By this amendment, § 282.202(a)(1) provides that those categories of "essential agricultural uses" certified by the Secretary of Agriculture after October 15, 1979, for Title IV purposes shall be reviewed by the Commission in a rulemaking procedure to determine whether those uses are appropriate uses for Title II "agricultural use" exemptions.

DATES: Interim rule effective October 6, 1980. Comments due: November 7, 1980. Public Hearing: October 28, 1980. Requests to participate by: October 21, 1980.

ADDRESSES: All comments and requests to participate to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. Public Hearing: Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Fern McGovern, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8066.

The Federal Energy Regulatory Commission (Commission) hereby promulgates an interim rule clarifying the scope of § 282.202(a) of its incremental pricing regulations under Title II of the Natural Gas Policy Act of 1978 (15 U.S.C. 3301–3432) (NGPA). The rule adopted in this docket amends § 282.202(a)(1) to provide that, for purposes of implementing the agricultural uses exemption from incremental pricing in section 206(b) of the NGPA:

(1) Those "essential agricultural uses" of natural gas that were certified by the Secretary of Agriculture (Secretary) on or before October 15, 1979, shall be considered "agricultural uses", and

(2) Any "essential agricultural uses" that are certified by the Secretary after October 15, 1979, shall be reviewed by the Commission in full rulemaking proceedings.

I. Background

Title II of the NGPA establishes a program of incremental pricing involving certain industrial uses of natural gas. The major portion of the program was implemented by the Commission in Order No. 49 (Docket No. RM79-14)[1] and Orders Nos. 50, 51, and 81 (Docket No. RM79-21).[2]

Title II also provides that certain uses of natural gas that would otherwise be subject to incremental pricing are to be exempted. The rule amended today deals with the section 206(b) exemption for agricultural uses of natural gas. The rule is specifically concerned with that portion of section 206(b)(3) which provides:

> (3) Agricultural Use Defined.—For purposes of this subsection, the term "agricultural use", when used with respect to natural gas, means the use of natural gas to the extent such use is—
>
> (A) for agricultural production, natural fiber production, natural fiber processing, food processing, food quality maintenance, irrigation pumping, or crop drying; or
>
> (B) as a process fuel or feedstock in the production of fertilizer, agricultural chemicals, animal feed, or food.

Regulations governing the agricultural use exemption were originally promulgated in Order No. 49 in Docket No. RM79-14. In § 282.202(a)(1) the Commission provided that "agricultural use" for purposes of incremental pricing includes:

> any use of natural gas which is certified by the Secretary of Agriculture under 7 CFR 2900.3 as an essential agricultural use pursuant to section 401(c) of the NGPA.

Questions have been raised as to the effect on the incremental pricing program of the Secretary's amendments to 7 CFR Part 2900, *i.e.*, changes in the Secretary's list of "essential agricultural uses" which took effect subsequent to the effective date of § 282.202(a)(1) (October 15, 1979). For the reasons discussed below, the Commission amends § 282.202(a)(1), on an interim basis, to resolve this question.

II. Discussion

When the Commission initially promulgated § 282.202(a)(1) in Order No. 49, it reviewed and accepted as "agricultural uses," for purposes of Title II, all categories then currently certified by the Secretary of Agriculture as "essential agricultural uses" for purposes of Title IV.[3]

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[1] Order No. 49 issued September 28, 1979, 44 FR 57726 (October 5, 1979). See also Order No. 49-A, issued December 27, 1979, 45 FR 767 (January 3, 1980); Order Denying Rehearing of Order No. 49-A, issued February 21, 1980, 45 FR 13065 (February 28, 1980).

[2] Orders Nos. 50 and 51, issued September 28, 1979, 44 FR 57754 (October 5, 1979); Order No. 81, issued May 7, 1980, 45 FR 31300 (May 13, 1980).

[3] Order No. 49, pp. 39–40.

Subsequent to the adoption of Order No. 49 the Secretary certified additional categories of essential agricultural uses for purposes of Title IV. This resulted in some confusion regarding the status of these additional categories for purposes of incremental pricing exemptions under Title II. In the "Order Denying Rehearing" of Order No. 49-A, issued February 21, 1980, *mimeo*, p. 4, the Commission noted that it would address at a later time this question of whether categories of natural gas use certified by the Secretary of Agriculture after October 15, 1979, would be automatically adopted by the Commission for incremental pricing purposes.

The Commission has received written comments in the context of Docket No. RM80-18 contending that uses of natural gas certified after October 15, 1979, by the Secretary under Title IV are automatically adopted by the Commission for incremental pricing purposes.[4] The Commission is acutely aware of its responsibility, as mandated by Congress, to oversee and implement Title II of the NGPA. The Conference Report directs the Commission to prescribe interim and permanent exemptions to the incremental pricing rules of sections 201 and 202 of the NGPA (NGPA Conf. Rept. No. 95-1126, 95th Cong. 2d. Sess., p. 101). Congress did not provide any direction to the Commission to delegate its responsibilities under Title II to the Secretary of Agriculture.[5] In view of this, the Commission rejects the commenters' arguments, and now promulgates an interim rule to clarify that its reference in § 282.202(a)(1) to categories certified by the Secretary of Agriculture does not include categories certified subsequent to October 15, 1979, the effective date of § 282.202(a)(1).

The interim rule further provides that each category subsequently certified by the Secretary will be reviewed by the Commission in order to determine whether § 282.202(a)(1) should be amended to include that category in the list of agricultural uses exempted from incremental pricing under section 206(b). The Commission will review each use certified after the effective date of this rule in the context of a rulemaking and will issue a Notice for Public Comment within 60 days after the date of publication in the Federal Register of such certification by the Secretary of Agriculture. The Commission will, of course, accord appropriate consideration to the Secretary's justification for such certification when making its own decision.

III. Summary of Additional Certifications Issued to Date

The Secretary of Agriculture has issued several amendments to 7 CFR 2900.2 and 2900.3 since October 15, 1979. Section 2900.2 is the definitional section; § 2900.3 lists for curtailment purposes those agricultural uses of natural gas which the Secretary has found to be "essential agricultural uses." As a result of these amendments, the following uses of natural gas have been certified as essential agricultural uses:

(1) The use of natural gas in sugar refining for the production of alcohol;

(2) The use of natural gas for agricultural production on set-aside acreage, such acreage being diverted from the production of a commodity and devoted to the production of any

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[4] Notice of Opportunity to Comment on Whether a Rulemaking Proceeding Should be Established, Docket No. RM80-18, issued February 21, 1980, 45 FR 13122 (February 28, 1980).

[5] Section 401 defines "essential agricultural use" for purposes of natural gas curtailments (Title IV). The definitions of "agricultural use" and "essential agricultural use" in Titles II and IV respectively are nearly identical, but differ in several important respects. First, the Title IV definition requires the Secretary of Agriculture to determine "essential agricultural uses." Second, Title IV requires the Secretary, in certifying "essential agricultural uses" to determine those agricultural uses which are "necessary for full food and fiber production," while Title II places no such restriction on the Commission. Lastly, Titles II and IV have very different goals. *See*, 44 FR 28784, May 17, 1979, wherein the Secretary of Agriculture stated that his certification of "essential agricultural uses" under Title IV "should not be construed as any indication of what is or is not an 'agricultural use' for the purpose of their (the Commission's) section of the NCPA, notably section 206."

commodity for conversion into alcohol or hydrocarbons for use as motor fuel or other fuels;

(3) The use of natural gas in the distillation of fuel-grade alcohol from food grains or other biomass by facilities that were in existence on the date of the enactment of the Energy Security Act and that do not have the installed capability to burn coal (a 5-year exemption);

(4) The use of natural gas in the production of petroleum wax, synthetic wax and polyethylene wax (food grade only) as food containers;

(5) The use of natural gas to raise steam which in turn is used as an integral part of the manufacturing process of fertilizer, agricultural chemicals, animal feed, and food; [6]

(6) The use of natural gas in the manufacture of metal crowns and closures (food containers only) used as container caps; and

(7) The use of natural gas in the manufacture of metal shipping barrels, drums, kegs and pails (food containers only).

The adoption of this interim rule makes it clear that the Secretary of Agriculture's certification of the above-listed uses of natural gas as "essential agricultural uses" under Title IV did not result in automatic adoption of these uses for purposes of Title II, and that each use shall be considered by the Commission on a case-by-case basis to determine whether it should be adopted for incremental pricing purposes.[7]

Exemptions for the uses described above in paragraphs (3), (4) and (7) have already been separately proposed to the Commission and are currently under consideration in Docket Nos. RM80-64 [use (3)] and RM80-48 [uses (4) and (7)]. Uses (1), (2), and (6) will shortly be the subject of Notices of Proposed Rulemaking or Inquiry as appropriate.

The use of natural gas described in paragraph (5) has also been brought before the Commission in Docket No. RM80-18 and has resulted in a "Notice of Opportunity to Comment on Whether a Rulemaking Procedure Should be Established" (45 FR 13122, February 28, 1980). Written comments have already been received in this docket, but the Commission will afford an opportunity for interested persons to present oral testimony on this issue. A Notice of Public Hearing will be issued shortly.

IV. Effective Date

As noted above, there has been a great deal of uncertainty regarding the effect of certifications by the Secretary of Agriculture after October 15, 1979. The Commission received, and has considered, written comments on the issue in the context of proceedings in Docket No. RM80-18.

The Commission believes that failure to resolve this uncertainty as quickly as possible would be contrary to the public interest. Accordingly, the Commission finds that good cause exists under 5 U.S.C. 553(b) and (d) to make the rule effective immediately. The Commission will, however, afford an opportunity for interested persons to present views and comments, as set forth below, before this rule is adopted in final form.

V. Comment Procedure

A. Written Comments

Interested persons are invited to submit written comments, data, views, or arguments with respect to this interim rule. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North

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[6] The Secretary of Agriculture actually effected this certification by means of the addition to § 2900.2 of the regulations of a definition of "process fuel" to which certain of the uses he previously certified were limited. *See* Amendment of Certification of Essential Agricultural Uses and Requirements, Natural Gas Policy Act of 1978, 45 FR 27741 (April 24, 1980).

[7] It should be noted that, in the list of uses adopted by the Commission and published in § 282.202(a)(1)(i) of the interim rule, "process and feedstock uses" have been purposefully omitted. Those categories of uses would have been published in the listing only if Phase II of the incremental pricing program had been approved by Congress.

Capitol Street, N.E., Washington, D.C., 20426 and should reference Docket No. RM80–75. An original and 14 copies should be filed. All comments received on or before November 7, 1980, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection through the Commission's Division of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., 20426, during regular business hours.

B. Public Hearing

A public hearing concerning this interim rule will be held on October 28, 1980, beginning at 9:00 a.m., at the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. Any person interested in this proceeding or representing a group or class of persons interested in this proceeding may make a presentation at the hearing provided a written request to participate is received by the Secretary of the Commission on or before Tuesday, October 21, 1980.

Requests to participate in the hearing should include a reference to Docket No. RM80–75, the amount of time required for the oral presentation, as well as a concise summary of the proposed oral presentation and a telephone number where the person making the presentation may be reached. Persons participating in the public hearing should if possible, bring 15 copies of their testimony to the hearing. A list of the participants in the hearing will be available in the Commission's Division of Public Information three days before the hearing and will be available at the site of the hearing on the morning it is convened.

Members of the hearing panel will be designated by the Chairman of the Commission. The hearing will not be a judicial or evidentiary-type hearing. There will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested person may submit questions to the presiding officer to be asked of persons making statements. The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. Any further procedural rules will be announced by the presiding officer at the hearing. A transcript of the hearing will be available in the public files for this proceeding, Docket No. RM80–75, through the Commission's Division of Public Information.

(Natural Gas Policy Act of 1978, Pub. L. No. 95–621, 92 Stat. 3350, 15 U.S.C. 3301–3432 *et seq.*)

In consideration of the foregoing, Part 282 of Chapter I, Title 18, Code of Federal Regulations, is amended on an interim basis, as set forth below, effective October 6, 1980.

By the Commission.

Lois D. Cashell,

Acting Secretary.

[¶ 30,196]

45 F. R. 68389 (October 15, 1980)

18 CFR Part 282

[Docket No. RM81–1]

Incremental Pricing; Interim Rule Adopting Revised Alternative Fuel Price Ceilings for the State of Rhode Island

Issued October 3, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Interim rule.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts an interim rule amending § 282.404 of its regulations. This amendment corrects a reporting error in the incremental pricing program by revising the alternative fuel price ceilings applicable to incrementally priced natural gas users in the State of Rhode Island for the months of May through September, 1980.

DATES: Interim rule effective October 3, 1980. Comments due: November 10, 1980. Public Hearing: October 28, 1980. Requests to participate by: October 21, 1980.

ADDRESSES: All comments and requests to participate should be mailed to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426. The public hearing will be held at the above address.

FOR FURTHER INFORMATION CONTACT:
Sandra Delude, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-9095,
or
Carol M. Lane, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8114.

SUPPLEMENTARY INFORMATION: The Federal Energy Regulatory Commission (Commission) hereby revises the alternative fuel price ceilings applicable to incrementally priced natural gas users in the State of Rhode Island for the months of May through September, 1980.

I. Background

Title II of the Natural Gas Policy Act of 1978 (NGPA)[1] requires this Commission to prescribe and make effective a program of incremental pricing of natural gas used as industrial boiler fuel. Section 204(e) of the NGPA directs the Commission to establish ceilings on prices charged to incrementally priced users such that the price paid for natural gas by the industrial user does not exceed the alternative fuel cost in the user's region.

Under the Commission's regulations implementing section 204(e), alternative fuel price ceilings for each month are published in the Federal Register on or before the 20th day of the preceding month. These prices are calculated by means of a formula which utilizes the prices of high sulfur No. 6 fuel oil in each of the 48 contiguous states observed during a previous period. The task of collecting the necessary data, applying the formula, and publishing the calculated alternative fuel price ceilings each month is carried out by the Energy Information Administration (EIA) of the Department of Energy.

II. Discussion

Section 204(e)(1) of the NGPA stipulates that the appropriate alternative fuel cost for each region shall be the price paid for the alternative fuel by industrial users in that region. The alternative fuel cost for the State of Rhode Island should therefore have been calculated upon the basis of prices paid to oil suppliers by industrial consumers in that State.[2] The Commission has learned, however, that the data reported to the EIA for Rhode Island erroneously reflected prices for No. 6 fuel oil sales that were made for storage, rather than for sales to industrial ultimate consumers.

The Commission asked the EIA to recalculate the alternative fuel price ceilings, using the correct data, for those months during which such recalculation would have an impact upon the prices charged non-exempt users in the State of Rhode Island.[3] The recalculated figures indicate that the correct ceilings for Rhode Island during those months are significantly lower than the published ceilings. For example, the correct ceiling for August is 58 cents lower than the published ceiling.

On the basis of this information, the Commission finds good cause to amend its regulations. Specifically, § 282.404(a) is amended by providing that the

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[1] 15 U.S.C. §§ 3301 *et seq.*

[2] Oil suppliers report their sales each month to the EIA on Form EIA-194.

[3] The recalculation was made for the months of May through September, 1980. Since non-exempt users in Rhode Island experienced no surcharges prior that period, a downward adjustment of the alternative fuel price ceilings prior to May would have no effect. For October and succeeding months, the EIA has ascertained that correct data is being reported.

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alternative fuel price ceilings for May through September for the State of Rhode Island shall be those set forth in that section rather than those previously published in the Federal Register by the EIA for those months.

With respect to the other 47 contiguous States, the EIA's recalculated figures for May through September indicate that the effect of the revised reporting from Rhode Island is either non-existent or causes a small increase in the price ceilings. The Commission has determined not to revise the alternative fuel price ceilings for States other than Rhode Island, because it finds that any benefit to the incremental pricing program which might be gained by such a revision would be outweighed by the adminstrative expense that would be placed upon pipelines, distribution companies, and end-users.

III. Refund of Overcharges

The Commission has determined that all surcharges billed to end-users in the State of Rhode Island to date have emanated from the supply system of the Providence Gas Company. This company has informed the Commission that, while it has notified its non-exempt customers that they have incurred incremental pricing surcharges, no collections of such surcharges have actually been made.[4] Accordingly, it will not be necessary to provide a mechanism for refund to those customers. The supplier may simply recalculate the surcharges and submit a revised bill.[5]

IV. Effective Date

The Commission believes that failure to grant relief as quickly as possible to incrementally-priced end-users in the State of Rhode Island would be contrary to the public interest. Accordingly, the Commission finds that good cause exists under 5 U.S.C. §§ 553 (b) and (d) to make this rule effective October 3, 1980, as an interim rule applicable to all incremental pricing surcharges in the State of Rhode Island for sales occurring in May–September, 1980. The Commission will, however, afford an opportunity for interested persons to present views and comments, as set forth below, before the rule is adopted in final form.

V. Comment Procedures

A. Written Comments

Interested persons are invited to submit written comments, data, views, or arguments with respect to this interim rule. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should reference Docket No. RM81-1. An original and 14 copies should be filed. All comments received prior to 4:30 p.m. EST, November 10, 1980, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection through the Commission's Division of Public Information, Room 100, 825 North Capitol Street, N.E., Washington, D.C., during regular business hours.

B. Public Hearing

Interested persons may request the opportunity for an oral presentation of their views at a public hearing. Requests for an oral hearing should be submitted no later than October 21, 1980, to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should reference Docket No. RM81-1. If a public hearing is held in this docket, it will be held at the above address on October 28, 1980, and will be announced by October 24, 1980.

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[4] *See*, Application for Adjustment filed by Providence Gas Company on September 22, 1980, Docket No. SA80-150.

[5] Providence has indicated to the Commission Staff that it has has already paid the surcharge amounts to its own supplier. The Staff has contacted this supplier and been informed that it and its suppliers will be able to effect any refunds by crediting their respective customers' surcharge accounts prospectively.

(Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301, *et seq.;* Department of Energy Organization Act, 42 U.S.C. §§ 7101, *et seq.;* E.O. 12009, 3 CFR 142 (1978))

In consideration of the foregoing, the Commission amends Subpart D, Part 282, Subchapter I, of Chapter I, Title 18 of the Code of Federal Regulations, on an interim basis, as provided below, effective October 3, 1980.

By the Commission. Chairman Curtis voted present.

Lois D. Cashell,
Acting Secretary.

[¶ 30,197]

45 F. R. 57708 (August 29, 1980)

18 CFR Part 141

[Docket No. RM80-63]

Discontinuance of Form RO211; Notice of Change of Effective Date

August 21, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of change of effective date.

SUMMARY: On June 2, 1980, the Federal Energy Regulatory Commission issued Order No. 89, "Discontinuance of Form RO211" (45 FR 38354, June 9, 1980). The reporting requirement, Form RO211 was to be eliminated, effective September 1, 1980. By this notice, the effective date of Order No. 89 is changed to December 31, 1980.

DATE: December 31, 1980.

FOR FURTHER INFORMATION CONTACT: Cathy Ciaglo, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Room 3329, Washington, DC 20426 (202) 357-8318.

SUPPLEMENTARY INFORMATION: The Federal Regulatory Commission's (Commission) Order No. 89, "Discontinuance of Form RO211," was issued June 2, 1980 (45 FR 38354, June 9, 1980). The reporting requirement, Form RO211, and its corresponding regulation set forth at 18 CFR 141.58 require a report of impending emergencies, load reductions and/or service interruptions in bulk electric power supply and related power supply facilities. The form is no longer necessary to the performance of the Commission's regulatory responsibilities. Form RO211 was issued with a delayed effective date of September 1, 1980 so as to allow the Economic Regulatory Administration (ERA) sufficient time to devise and receive approval for its own form which would collect the information in Form RO211 that ERA needed to perform its statutory responsibilities.

The Commission has learned that ERA has not completed its rulemaking process to effect such a form, and does not expect to implement regulations which would include the reporting requirement RO211 until late December 1980. The Commission is, therefore, extending the effective date for elimination of Form RO211 to December 31, 1980.

Kenneth F. Plumb,
Secretary.

[¶ 30,198]

45 F. R. 71563 (October 29, 1980)

18 CFR Part 271

[Docket No. RM79-76; Order No. 99-A]

High-Cost Natural Gas Produced for Tight Formations; Order Denying Rehearing and Clarifying Order No. 99

Issued October 21, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: On August 15, 1980, the Federal Energy Regulatory Commission issued Order No. 99 in Docket No. RM79-76 (45 FR 56034, August 22, 1980).

In Order No. 99, the Commission established an incentive price under section 107 of the Natural Gas Policy Act of 1978 for gas produced from designated tight formations and set forth the procedure for designation of tight formations and for well category determinations.

This order denies applications for rehearing of Order No. 99 and amends the applicability section and the definition of tight formation gas to clarify that a producer is not required to have a negotiated contract in order to apply for or receive a well category determination. In addition, technical amendments have been made to the definition of negotiated contract price.

EFFECTIVE DATE: October 21, 1980.

FOR FURTHER INFORMATION CONTACT:
Colette Bohatch, Federal Energy Regulatory Commission, Room 8100–B, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357–8033
or
June Perin, Federal Energy Regulatory Commission, Room 8000, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357–8473.

On August 15, 1980, the Federal Energy Regulatory Commission (Commission) issued Order No. 99 in Docket No. RM79–76 (45 FR 56034, August 22, 1980). Applications for rehearing of Order No. 99 were filed by Pennzoil Company, *et al.*[1] (Pennzoil Group) and Kentucky West Virginia Gas Company (Kentucky-West Virginia).

In Order No. 99, the Commission established an incentive price under section 107 of the Natural Gas Policy Act of 1978 (NGPA) for gas produced from designated tight formations and set forth the procedure for designation of tight formations and for well category determinations.

I. Application of the Pennzoil Group

The Pennzoil Group argues that Order No. 99 will delay producers' efforts to bring increased supplies of gas into the domestic market. The following reasons given by the Pennzoil Group to support its application do not warrant a rehearing. All of the issues presented by the Pennzoil Group and discussed below have been fully considered by the Commission during this rulemaking process.

A. *Designation of tight formations.*—The Pennzoil Group argues that the Order No. 99 procedures for nominating and approving tight formations could be streamlined by substituting the procedures of section 503 of the NGPA.

The Commission has the discretion to qualify tight formations under either section 503 or by rulemaking. For the reasons enunciated in the preamble to the final rule, the Commission will continue to designate tight formations by rule in accordance with the provisions of § 271.703.

B. *Order No. 99 pricing provision.*—The Pennzoil Group also raises a question regarding the pricing provision of Order No. 99. In Order No. 99, the Commission established a ceiling price for gas produced from designated tight formations. That ceiling price as set forth in § 271.703(a) is 200 percent of the maximum lawful price under section 103 of the NGPA or the negotiated contract price, whichever is less. The term "negotiated contract price" as defined in § 270.702(a)(1) means:

> Any price established by a contract which either specifically references the incentive pricing authority of the Commission under section 107 of the NGPA or contains a fixed rate or a fixed escalator clause.[2]

On this point, the Pennzoil Group argues in its rehearing application that:

> Section 101(b)(9) of the NGPA and the *Mobile-Sierra* doctrine provide a rule of

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[1] This application for rehearing was filed jointly by Pennzoil Company, Pennzoil Producing Company, Pennzoil Oil and Gas, Inc., Pogo Producing Company, Great American Oil Company of Texas, Texas Gulf, Inc., and Ashland Exploration, Inc.

[2] Certain clarifying amendments to this definition are now being adopted by the Commission.

> construction that the private contractual rights of producers and pipelines are preserved inviolate *as long as their exercise of those rights does not result in the collection of a price which is in excess of the maximum lawful price.* As such, the Commission has no jurisdiction to abrogate or interfere with the exercise of private contractual rights by producers and pipelines. By requiring certain words to be used in a contract, and especially by imposing this requirement retroactively, the Commission has violated section 101(b)(9) of the NGPA and the *Mobile-Sierra* doctrine. [Emphasis added.]

This argument begs the question. Under Order No. 99, no incentive maximum lawful price is applicable unless the contract covering the sale of the tight formation gas contains a clause which specifically references the Commission's section 107(c) incentive pricing authority or which is a fixed rate or a fixed escalator clause. The Commission adopted this pricing provision to assure that a price collected under a contract is necessary to increase gas production.[3] The Commission emphasizes that parties are not barred from renegotiating their contracts to qualify for the Order No. 99 ceiling price.[4]

The Pennzoil Group also argues that section 105(b)(3)(D)[5] and section 313(a)[6] mandate that "broadly drafted indefinite price escalator clauses" provide contractual authority for collection of a section 107(c) price.

We disagree. Both sections are couched in the negative. Sections 105(b)(3) and 313(a) impose limitations on the operation of indefinite price escalator clauses. They do not mandate collection of a section 107(c) price where such clauses exist.

C. *Other issues.*—The Pennzoil Group raises other issues regarding the sufficiency of the price and certain requirements for well category determinations and for designation of tight formations. The Commission rejects the arguments raised by the Pennzoil Group on the respective provisions of Order No. 99 for the reasons stated in Order No. 99.

II. Application of Kentucky-West Virgina

Kentucky-West Virginia submits that the Commission unlawfully excluded certain sales of pipeline production from the final rule by failing to include, explicitly, sales of such production within the definition of first sale.

Incentive prices established by the Commission under section 107 like all other maximum lawful prices under Title I of the NGPA are applicable to first sales of natural gas. In Order No. 58, the Commission addressed the issue of first sale treatment of sales made by pipelines, distributors, and their affiliates.[7] All issues raised by Kentucky-West Virginia regarding Order No. 99 relate to the Commission's definition of a first sale in Order No. 58.

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[3] As stated in the preamble to Order No. 99:

The Commission reaffirms the position taken in the interim rule that it must limit the availability of the incentive price ceiling to those contracts which specifically refer to it (or to the extent permitted under a fixed rate or fixed escalator clause) because its pricing authority is limited to setting incentive prices "necessary" to encourage additional production. (Mimeo, at p. 37.)

[4] The negotiated contract price requirement appears in the production enhancement rulemaking as a qualification for gas. Similar arguments questioning the Commission's role have been raised in the production enhancement rulemaking and will be addressed there.

[5] Section 105(b)(3) imposes certain limitations on the effect of indefinite price escalator clauses. Section 105(b)(3)(D) establishes an exclusion for certain categories of gas from such limitations.

[6] Section 313(a) provides:

High-Cost Natural Gas.—No price paid in any first sale of high-cost natural gas (as defined in section 107(c)) may be taken into account in applying any indefinite price escalator clause (as defined in section 105(b)(3)(B)) with respect to any first sale of any natural gas other than high-cost natural gas (as defined in section 107(c)).

[7] Section 270.203 promulgated in Order No. 58, provides that a sale by a pipeline or distributor is not a first sale unless the sale is comprised exclusively of production by the pipelines or distributors or the sale is a mixed volume sale the price of which is not regulated pursuant to the Natural Gas Act (15 U.S.C. §§ 717–717w) or by a state agency empowered by statute to establish, modify, or set aside the rate for such sale.

Therefore, they are outside the scope of this rulemaking and the application for rehearing must be denied.

III. Clarification of Order No. 99

Three clarifying amendments have been made to the final rule. The applicability provision of § 271.701 has been amended to delete the reference to a jurisdictional agency determination. The purpose of this amendment is to clarify that a producer is not required to have a negotiated contract price in order to apply for or receive a well category determination from a jurisdictional agency. A corresponding clarifying amendment has been made to the definition of tight formation gas in § 271.703(b)(1). Finally, certain clarifying amendments have been made to the definition of negotiated contract price in § 271.702(a)(1).

Because these amendments effect no substantive change in the rule but are necessary for proper implementation of the rule, the Commission finds that public notice and comment is unnecessary. For the same reasons, the amendments are being made effective immediately. (5 U.S.C. 553)

The Commission orders:

(1) The applications for rehearing of Order No. 99 filed jointly by the Pennzoil Company, Pennzoil Producing Company, Pennzoil Oil and Gas, Inc., Pogo Producing Company, Great American Oil Company of Texas, TexasGulf, Inc., and Ashland Exploration, Inc. and Kentucky-West Virginia Gas Company are denied.

(2) Order No. 99 is clarified by amending §§ 271.701, 271.702(a)(1) and 271.703(b)(1) of the Commission's regulations as set forth above, effective October 21, 1980.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301, *et seq.*; Department of Energy Organization Act, 42 U.S.C. § 7107, *et seq.*; Executive Order No. 12009. 42 FR 46267, Natural Gas Act, as amended, 15 U.S.C. 717, *et seq.*)

In consideration of the foregoing, Part 271 of Subchapter H, Chapter I, Title 18, Code of Federal Regulations is amended as set forth below, effective October 21, 1980.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶30,199]

45 F. R. 71778 (October 30, 1980)

18 CFR Part 271

[Docket No. RM79-76 (Texas-1); Order No. 105]

High-Cost Gas Produced From Tight Formations

October 24, 1980.

AGENCY: The Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high cost gas subject to an incentive price (18 CFR 271.703). The rule establishes procedures for jurisdictional agencies to submit to the Commission recommendations for designating areas as tight formations. This final order adopts the recommendation of the Texas Railroad Commission that the Cotton Valley Sandstone, the Bossier Shale, and the Cotton Valley Lime Formations be designated as tight formations.

EFFECTIVE DATE: October 24, 1980.

FOR FURTHER INFORMATION CONTACT:
Leslie Lawner, Federal Energy Regulatory Commission, Room 4308B, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357-8299, or

William Bushey, Federal Energy
Regulatory Commission, Room 6106,
825 North Capitol Street, NE.,
Washington, D.C. 20426, (202) 357–8590.

I. Background

On July 11, 1980, the Texas Railroad Commission (Texas) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations, that the Cotton Valley Sandstone Formation, the Bossier Shale Formation, and the Cotton Valley Lime Formation (known collectively as the Cotton Valley Group) be designated as tight formations in the Commission's regulations. On August 15, 1980, a Notice of Proposed Rulemaking was issued by the Director of the Office of Pipeline and Producer Regulation (OPPR) in Docket RM79–76 (Texas–1) (45 FR 56072, August 22, 1980), to determine if Texas' recommendation that the Cotton Valley Group be designated as tight formations should be adopted. The Director of OPPR issued the notice pursuant to the authority delegated to him by Order No. 97, Docket No. RM80–68, issued on August 1, 1980 (45 FR 53456, August 12, 1980).

Interested persons were given until September 29, 1980, to submit written comments and information concerning Texas' recommendation. No party requested a hearing in this matter, and no hearing was held.

II. Discussion

The Commission, on February 20, 1980, issued an Interim Rule in Docket No. RM79–76 establishing a procedure for designating tight formations and for qualifying gas wells completed in those formations for section 107 high cost gas incentive prices. The recommendation filed by Texas was submitted under the Interim Rule. The procedures and requirements delineated in the Interim Rule were not significantly changed in the Final Rule issued by the Commission on August 15, 1980 (Order No. 99). In this rule the Commission delegated the initial responsibility for identifying potentially qualifying tight formations to each jurisdictional agency. The rule requires jurisdictional agencies to establish procedures and conduct their own investigations to identify tight formations within their own jurisdictions that meet the guidelines established by the Commission. The jurisdictional agencies will then submit written recommendations to the Commission that particular formations or portions thereof be designated as tight formations.

On May 20, 1980, Texas held a public hearing in Austin for the purpose of receiving nominations and supporting data regarding formations that might be considered tight formations. At that time ten formations were suggested by participants as meeting the requirements for tight formations. After study of the data submitted at the hearing and collection of additional data, on July 15, 1980, Texas recommended to the Commission that the Cotton Valley Sandstone, the Bossier Shale and the Cotton Valley Lime Formations, comprising the Cotton Valley Group, be designated as tight formations.

A. Summary of the Texas Recommendation

The formations in the Cotton Valley Group are located in the northeastern part of the state of Texas, underlying 48 counties in Railroad Commission Districts 1, 3, 5 and 6.

Northern limits of the recommended formations lie immediately south of the Texas-Oklahoma border through Fannin, Lamar, and Red River Counties and the eastern limit extends to the borders of Arkansas and Louisiana. The southern boundary is determined by the Angelina-Caldwell flexture from Sabin through San Augustine, Angelina, and Trinity Counties. The western boundary is determined by the Mexia-Talco fault zone through Limestone, Navarro and Kaufman Counties.

Within the Cotton Valley Group, the Cotton Valley Sandstone lies above the Bossier Shale with the Cotton Valley Lime immediately below the Bossier Shale. The average depth of the Cotton Valley Sandstone is approximately

7,000' to the north, 8,000' to the east, between 10,000' and 11,000' to the south, and 5,000' to the west. The Cotton Valley Sandstone reaches a maximum thickness of 1,600'. The top of the Bossier Shale is located at depths of approximately 7,700' to the north, 10,720' to the east, 12,600' to the south and 5,340' to the west. The Bossier Shale ranges from 110' to 560' in thickness and contains laminated sand bodies up to 90' thick. The Cotton Valley Lime can be found at depths of approximately 8,000' to the north, 11,400' to the east, 13,200' to the south, and 5,500' to the west.

Texas' geologic description of the formation in question includes discussions on depositional history, structure, stratigraphy and detailed lithologies. Included in the submission were core samples of the Cotton Valley Sand and the Cotton Valley Lime. Texas enclosed a list of 1,896 wells thought to be deep enough to have penetrated the Cotton Valley Group. These wells are located on county base maps. Additionally, Texas has submitted a list of 900 wells, located in Districts 5 and 6, which have been completed as gas producers in the Cotton Valley Group and indicates that at least 36 of these wells were completed after July 16, 1979, and would thus be eligible for the tight formation gas incentive prices.

Texas briefly describes those federal and state regulations which serve to assure that the development of these formations will not adversely affect the quality of fresh water aquifers. Texas also points out that most Cotton Valley Group wells are completed at a depth of 8,000 feet or greater while the deepest fresh water aquifer in Districts 5 and 6 is approximately 500 feet. This well depth difference of about 7,500 feet helps to protect the integrity of the fresh water aquifers.

B. Comments

Comments on the proposed rule were received from ten parties. All parties expressed support for the recommendation. Exxon also supported the recommendation and requested additional time in which to file additional data on 43 wells which have been drilled in the Cotton Valley Lime. An extension was granted until October 8, 1980.

C. Guidelines for Designation

In § 271.703(c)(2)(i) of the regulations, the Commission has established guidelines which a formation must meet to be designated as a tight formation. These are:

(1) The average *in situ* gas permeability throughout the pay section is expected to be 0.1 millidarcy or less;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production in the formation, without stimulation, is not expected to exceed production rates delineated in the table in § 271.703(c)(2)(i)(B) of the regulations;

(3) No well drilled into the recommended formation is expected to produce, without stimulation, more than five barrels of crude oil per day.

(4) Any formation or portion thereof which has been authorized to be developed by infill drilling prior to the date of recommendation must be excluded from the recommendation, if the jurisdictional agency has information which in its judgment indicates that such formation or portion thereof can be developed absent the incentive price for tight formations.

A summary of the data submitted by Texas confirming that wells completed in the Cotton Valley Group are expected to meet the guidelines is given below. Average permeabilities, average flow rates for oil and gas before stimulation and average depths for the three formations, are given below:

Formation	Number of data wells	Average permeability	Average depth	Average gas rate	Average oil rate
Cotton Valley Sandstone	126	0.042 md.	10,187'	289Mcf/d	O BPD
Bossier Shale	2	.0368 md.	12,291'	586Mcf/d	O BPD
Cotton Valley Lime	73	.0321 md.	12,406'	495Mcf/d	O BPD

The majority of permeability and flow rate data is derived from Harrison, Panola, and Rusk Counties for the Cotton Valley Sandstone. Data for the Bossier Shale and Cotton Valley Lime Formations comes primarily from Freestone and Limestone counties. However, data from areas where information is limited appears to be closely parallel to data determined in counties where the information is more plentiful.

1. *Permeability.* Data provided by Texas describes four methods of determining *in situ* permeability. These are: (1) Pressure build up (PBU) analysis; (2) Side-wall core (SWC) analysis, under atmospheric conditions and at reservoir conditions; (3) Drawdown test data and radial flow equations; and (4) Pressure build up models.

Using PBU analysis, Texas determined that the average permeability in the Cotton Valley Sandstone was 0.0231 md. In side-wall core tests, Texas determined that the core permeability, with overburden pressure applied, was 0.0053 for the Cotton Valley Sandstone. Calculations using the radial flow equations indicated average *in situ* permeabilities of 0.042 md. for the Cotton Valley Sandstone, 0.0368 md. for the Bossier Shale and 0.0514 md. for the Cotton Valley Lime. An average *in situ* permeability of 0.0125 md. for the Cotton Valley Sandstone was calculated using the mathematical model. The above results and the supporting evidence demonstrate that, under several methods used for determining permeability, the vast majority of wells drilled into the Cotton Valley Group have *in situ* permeabilities below 0.1 md.

2. *Stabilized production rates.* Stabilized production rates were calculated from absolute open flow calculations using a ratio of flow equations. Average pre-stimulation flow rates for each formation are as follows: Cotton Valley Sandstone—289/Mdf/D at an average depth of 10,187'; Bossier Shale—586 Mcf/D at an average depth of 12,291; and Cotton Valley Lime—495 Mcf/D at an average depth of 12,406'. Tests results show that 96 percent of all Cotton Valley Sandstone wells for which prestimulation data was available have rated below the maximum permissible rates. Similarly, 95 per cent of the Cotton Valley Lime wells were below the maximum permissible rates. None of the wells completed in the Bossier Shale exceeded the established guidelines.

3. *Oil Production.* Only 30 of the 930 wells completed in the Cotton Valley Group produce oil. According to testimony supplied by Texas, it is apparently accepted by the industry that wells drilled into the Cotton Valley Group will be gas producers with little or no oil. The majority of liquids produced from Cotton Valley Group wells have been shown to be condensate that is in the gaseous phase within the reservoir. Thus, there is little chance that a well completed on the Cotton Valley Group will produce in excess of 5 barrels of oil per day prior to stimulation.

4. *Infill Drilling.* In accordance with § 271.703(c)(2)(i)(D), Texas reports in its recommendation that the Dirgin Field in Rusk County had been drilled consistent with field rules and that a subsequent amendment to the field rules reduced the unit size in this field. Texas states that the request for the reduction in unit size was received subsequent to

publication of the Notice of Proposed Rulemaking for the tight formation incentive price. Texas also states that it has no information that infill drilling would occur in this portion of the recommended formations absent the expectation of the tight formation incentive price.

D. Conclusion

The Commission has reviewed Texas' recommendation and the comments received in support thereof, and finds that the recommendation complies with the requirements of § 271.703(c)(3) of the regulations concerning the contents of the recommendation. The Commission concurs with Texas' assertion, based on the consideration of the record which Texas submitted, that the Cotton Valley Group meets all the requirements for designation as a tight formation set forth in § 271.703(c)(2)(i).

III. Effective Date

The Commission hereby makes this amendment to its regulations effective upon the date of issuance of this order. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis and, therefore, incentive prices for this gas should be made available as soon as possible. Therefore, good cause exists to waive the thirty day notice period preceding the effective date of the rule.

(Department of Energy Organization Act, (42 U.S.C. 7101 *et seq.*); Natural Gas Policy Act of 1978, (15 U.S.C. 3101–3432))

For the reasons stated herein, Part 271 of Subchapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective immediately.

By the Commission

Kenneth F. Plumb,
Secretary.

[¶ 30,200]

45 F. R. 71781 (October 30, 1980)

18 CFR Part 282

[Docket No. RM79-47; Order No. 103]

Federal Energy Regulatory Commission

State-Wide Exemptions From Incremental Pricing; Final Rule

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is amending its regulations under Title II of the Natural Gas Policy Act of 1978 (18 CFR Part 282) by adding new §§ 282.104 and 282.208 relating to State or local incremental pricing plans and alternative plans and by revising § 282.504. With respect to State or local incremental pricing plans, new § 282.104 makes clear that nothing in the Commission's incremental pricing regulations precludes a State or local government, or agency thereof, from implementing a State or local incremental pricing plan. Revisions to § 282.504 (e)(2) and (3) relieve some natural gas suppliers from the reporting requirements set forth in those sections. With respect to State or local alternative plans, new § 202.208 establishes procedures for approval of such plans.

EFFECTIVE DATE: October 21, 1980.

FOR FURTHER INFORMATION CONTACT: Barbara K. Christin, Office of the General Counsel, (202) 357–8428.

SUPPLEMENTARY INFORMATION: Final rule.

Issued: October 21, 1980.

I. Introduction

The Federal Energy Regulatory Commission (Commission) is amending its regulations under Title II of the Natural Gas Policy Act of 1978 (18 CFR Part 282) by adding new §§ 282.104 and 282.208 relating to State or local incremental pricing plans and alternative plans and by revising § 282.504. With respect to State or local incremental pricing plans, new § 282.104 makes clear that nothing in the Commission's incremental pricing regulations precludes a State or local government, or agency thereof, from implementing a State or local incremental pricing plan. Revisions to §§282.504(e)(2) and (3) relieve natural gas suppliers subject to a State or local incremental pricing plans from the reporting requirements set forth in those sections. With respect to State or local alternative plans, new § 282.208 establishes procedures for approval of such plans.

Under section 201 of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3301–3432), the Commission is required, within certain guidelines, to institute and administer a federal incremental pricing program. The program is designed to pass through, by surcharge, to certain industrial boiler fuel users of natural gas, a portion of the increases in the wellhead prices of natural gas allowed under title I of the NGPA. On September 28, 1979, the Commission issued final regulations implementing section 201 (Dockets Nos. RM79–14 and RM79–21, 44 FR 57726, October 5, 1979).

In the course of developing rules implementing Title II of the NGPA, the Commission identified two types of State ratemaking action that appeared to have some effect on the Commission's incremental pricing program: State incremental pricing plans and State alternative ratemaking plans. On July 3, 1979, the Commission issued a notice in this docket (44 FR 40898, July 13, 1979) requesting comments on whether a rulemaking proceeding should be initiated with respect to the relationship between the Commission's incremental pricing program and these two types of State ratemaking action. In response to the comments, the Commission issued a Notice of Proposed Rulemaking (Notice) in this docket on December 21, 1979 (45 FR 1081, January 4, 1980). On February 5, 1980, the Commission conducted an informal hearing for the presentation of oral comments on the Notice. Written comments in response to the Notice were filed by, among others, State public utility commissions, interstate natural gas companies, local distribution companies, and exempt and non-exempt users of natural gas.

II. Discussion of Issues and Comments

A. *State Incremental Pricing Plans.* Title II of the NGPA states that the surcharge imposed on an industrial facility under the incremental pricing program may not raise the facility's cost of non-exempt volumes of natural gas above the alternative fuel price ceiling set by the Commission. The Commission's regulations refer to this limit as the maximum surcharge absorption capability (MSAC) of the user. The MSAC is generally the difference between the user's alternative fuel price ceiling and the lower, State-established retail rate for natural gas paid by the user.

A State incremental pricing plan is a plan under which a State establishes its retail rate structure so that the retail price of natural gas to non-exempt users is maintained at, or above, the applicable alternative fuel price ceiling established by the Commission. The effect of such a rate plan is to eliminate any surchage that would otherwise be imposed on those users under the Commission's incremental pricing program. The MSAC within a State would thus become zero.

Validity of State incremental pricing plans. In the Notice, the Commission considered whether the elimination of the federal surcharge resulting from implementation of a State incremental pricing plan is consistent with Title II of the NGPA and the Commission's incremental pricing program. The Commission expressed the preliminary view that State incremental pricing plans are fundamentally consistent with both the NGPA and the Commission's program, and that, as a matter of law, the Commission could not prevent States from raising retail rates for non-exempt users to, or above, the alternative fuel price ceilings. Thus, States would not have to seek either Commission approval or Congressional approval under section 206(d) to implement their own incremental pricing plans.

Although most of the commenters addressing this issue agreed with the Commission's preliminary view, various arguments were raised by the remaining commenters contending that State incremental pricing plans are invalid.

Some commenters argued that the elimination of the federal surcharge violates section 205 of the NGPA. Section 205(d) prohibits a State from preventing the passthrough of any portion of the surcharge to a non-exempt user. Section 205(b) prohibits a State from changing the rates charged by a local distribution company to a non-exempt industrial facility, if the change has the effect of creating an offset for any portion of the federal incremental pricing surcharge paid by the local distribution company.

The Commission does not believe that State incremental pricing plans violate section 205. Although section 205 precludes State ratemaking bodies from reducing the impact, or preventing the imposition, of a surcharge on incrementally-priced gas users, that section does not speak to the amount of such surcharge. Section 204(c)(3) governs the amount of the surcharge and generally provides that the amount of the surcharge must not cause the total price for natural gas paid by a non-exempt user to exceed the user's alternative fuel cost. Part of that total price paid by the non-exempt user is the retail rate set by the State ratemaking authority, on which the NGPA sets no limit. In fact, the Statement of Managers stated that:

> The conference agreement does not preclude State regulatory agencies from exercising their authority under State law to regulate local distribution companies. A State regulatory agency could for example, raise prices to be paid by incrementally priced industrial facilities to levels higher than the levels required by this Title. The conferees have not mandated such a practice; nor has it been precluded. State law is not preempted in this case and States may wish to place more of the costs of service onto a particular class of industrial users. The conferees make no judgment as to the advisability of this action. S. Rep. No. 1126, 95th Cong., 2d Sess. 100–101 (1978).

This statement is a clear expression of Congressional intent not to preempt States from raising rates for their industrial gas users to, or above, their alternative fuel costs. Indeed, at one point in the Statement of Managers, the conferees recognized and did not object to the fact that some States may have already taken such action. (*See* S. Rep. No. 1126, quoted at p. 8 *infra*.)

Commenters also argued that State incremental pricing plans are invalid because they frustrate the objectives of incremental pricing. One of the purposes of the incremental pricing program "market ordering," is to prepare the natural gas market for deregulation in 1985. Congress anticipated that, by initially raising the price of gas delivered to large, price-sensitive industrial customers to a level at which further increases would threaten to cause loss of industrial load, pipelines, whose revenues depend upon volumetric throughput, would attempt to minimize further increases in the cost of gas that might occur upon deregulation, for fear that industrial demand would decline. (*See* Order No. 80, Docket No. RM80–10, issued May 7, 1980, pp. 8–9). The commenters contended that State incremental pricing plans frustrate the market ordering purpose of Title II, because non-exempt users in a State with a State incremental pricing plan pay a price for natural gas that is at least as high as the alternative fuel price ceiling, which prevents those users from feeling the impact of the higher gas prices allowed by Title I of the NGPA and paid by their interstate pipeline suppliers. Moreover, the federal surcharge paid by non-exempt users in a State without a State incremental pricing plan generally will bring the users' cost of gas up to the applicable alternative fuel price ceiling, because with a smaller class of non-exempt users to absorb the federal surcharges, it is improbable that the surcharge imposed will be less than the maximum.

Other commenters contended that State incremental pricing plans blunt the other purpose of Title II of the NGPA, the sheltering of residential and other high priority customers from rising gas prices allowed by Title I of the NGPA. They argued that, because a State plan eliminates the MSACs within the State, there remain more incremental gas acquisition costs, determined under section 203 of the NGPA, to be borne ultimately by residential and high priority gas users.

Related to this argument was the suggestion that the Commission modify its incremental pricing plan to prevent a State from improperly eliminating the federal surcharges within its borders. Under the Commission's program, the amount of the surcharges is tied to retail rates established at the State level. The commenters proposed that the surcharge be tied to something other than State retail rates, suggesting, for example, that they be tied to benchmark rates based on the historic relationship between the rates of industrial and high priority users. The Commission does not adopt this proposal, because it would result in some non-exempt users paying an ultimate price for natural gas higher than the alternative fuel price ceiling. This result would violate section 204 of the NGPA.

In addition to the reasons discussed above, the Commission is convinced that any doubt as to the legality of State incremental pricing plans under Title II, due to their effect either on the Commission's program or on the objectives of incremental pricing, is allayed by the clear indications of Congressional intent contained in the Statement of Managers. The Congress anticipated, and did not disapprove, the effect on incremental pricing surcharges of State action to raise industrial retail rates to, or above, alternative fuel price ceilings. In the Statement of Managers, the conferees stated that:

> The Commission is accorded flexibility by the conference agreement to make necessary adjustments in the calculation of the surcharge to be passed through. For examples [sic], in some instances State regulations may already provide some form of incremental pricing which has resulted in the fuel price paid by industrial facilities (which will qualify as incrementally priced industrial facilities under this Title) already equalling the Btu-equivalent price of alternative fuel. The conferees do not intend the operation of [section 201] to require the surcharge to be passed through to such facilities. S. Rep. No. 1126, 95th Cong., 2d Sess. 96 (1978).

Accordingly, the Commission concludes that it cannot legally preclude States from implementing their own incremental pricing plans and that such plans are consistent with Title II of the NGPA pursuant to which the Commission's incremental pricing rules were issued. This Commission has attempted to implement the incremental pricing program with minimal interference with the States' ratemaking authority, recognizing that the States' implementation of their own incremental pricing programs is a proper exercise of the States' authority to set retail rates.

The final argument with respect to the validity of State plans is that State incremental pricing plans violate section 4(b) of the Natural Gas Act (NGA), 15 U.S.C. 717 *et seq.* That section prohibits an interstate natural gas pipeline from maintaining any unreasonable difference in rates between localities or between classes of service. If States implement their own incremental pricing plans, natural gas users (both exempt and non-exempt) will experience differing impacts from incremental pricing depending upon the State in which they are located, due to varying State incremental pricing plans and the differing composition of gas users from State to State,[1] as well as differences between the various State plans and the Commission's plan.

The Commission does not agree that State incremental pricing plans violate section 4(b) of the NGA. Section 4(b) forbids only "unreasonable" differences in prices. Differences that arise from the lawful actions of state regulators pursuant to their authority to set rates within their individual States are not unreasonable and therefore do not violate the NGA. Furthermore, the statutory scheme embodied in Title II of the NGPA does not restrict States in the exercise of their ratemaking powers, except in the narrow area where State section is taken to offset or to prevent the passthrough of, a surcharge, as previously discussed.

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[1] As comments pointed out, depending on the particulars of a State incremental pricing plan, imbalances may even be from one local distribution company to another within the State. This result may occur because the pertinent ratemaking agency may not have the authority to shift the benefits of its incremental pricing plan from an area served by one local distribution company to an area served by another company.

Moreover, even if the Commission had the authority to intervene, the public interest is better served by minimal federal intervention in the traditional State function of setting retail rates. Each State's retail gas rates reflect that State's response to the unique set of circumstances present within its boundaries. The regulatory scheme of the NGPA contemplates such decision-making by States, and Title II of the NGPA builds upon State ratemaking and does not supplant it. Were the Commission to undertake a State-by-State balancing and an elimination of differences among State plans, the result would be federal involvement in the determination of local retail rates. Such an involvement would have costs and negative impacts far outweighing any potential benefits. A further extension of federal regulation should be based on a clear showing of need and public interest which has not been made here.

Allocation of additional revenues from State plans. The Commission's regulations do not require States to allocate to their residential and other high priority users the additional revenues collected from their non-exempt users whose rates are raised to, or above, the alternative fuel cost ceiling.

Several State commissions argued that the additional revenues must be reallocated so as to lower the rates of residential and other high priority users, because one of the purposes of Title II of the NGPA is to shield those users.

Although the Commission anticipates, as discussed in the Notice, that States with their own incremental pricing plans will endeavor to shield residential and other high priority users from higher gas prices to the extent possible under State law, the Commission cannot legally require States to channel the additional revenues to those high priority users. The incremental pricing program under Title II of the NGPA does not apply to residential and other high priority users of natural gas. Consequently, the traditional State retail ratemaking authority as to those users is undisturbed and the State may establish rates for those users in any manner consistent with State law. The Commission has no authority to require a State to channel to residential and other high priority users any increased revenues collected as a result of that State's implementation of its own incremental pricing plan.

One commenter suggested that any additional revenues reflecting the portion of non-exempt user rates exceeding the alternative fuel price level may be allocated at the discretion of the State regulatory body. The Commission rejects this suggestion insofar as it may imply that such allocation would result in retail rates for some non-exempt users which are lower than the alternative fuel price ceiling. By definition, these State incremental pricing plans establish rates for all non-exempt users at, or above, the user's alternative fuel price ceiling. If the rate charged any non-exempt user falls below the alternative fuel price ceiling, then that user has the ability, and is required, to absorb a surcharge imposed under the Commission's incremental pricing plan, regardless of the makeup of the State plan. Thus, a State plan is not in conformance with Title II of the NGPA and the Commission's incremental pricing regulations if such plan channels to some non-exempt users certain revenues collected from other non-exempt users and in the process causes some non-exempt user rates to fall below the applicable alternative fuel price ceilings.

Users exempted by section 206 of the NGPA. Section 206 of the NGPA exempts from the federal incremental pricing program several categories of gas users, such as small industrial facilities, agricultural users, schools, and hospitals. Related to the preceding discussion of the Commission's lack of authority to require States to channel increased revenues to residential and other high priority users is the issue of whether States with their own incremental pricing plans must preserve the exempt status of those gas users protected under the Commission's plan pursuant to section 206 of the NGPA. For example, may agricultural users of natural gas, who are exempt under section 206(b), be priced at, or above, the alternative fuel price ceiling under a State incremental pricing plan? Many end-users maintained that the exempt status of users under the Commission's plan must be preserved at the State level because to do otherwise is contrary to the mandate of section 206.

As previously discussed, Title II of the NGPA does not preempt State ratemaking authority with respect to exempt users. Specifically, regardless of whether the States implement their own incremental pricing plans or remain under the Commission's plan, there is no requirement in Title II that States must set lower rates for users who are exempt under the Commission's plan. Accordingly, the Commission does not view action by States to raise the rates to users exempt from the Commission's program by section 206 as a circumvention of Title II; rather, the Commission views such action as a valid exercise by the States of their traditional retail ratemaking authority.

"No greater harm" provision. Several commenters recommended that a "no greater harm" provision be included in the final regulations governing State incremental pricing plans. A "no greater harm" provision would allow States under their own incremental pricing plans to set their rates for non-exempt users below the applicable alternative fuel price ceilings, if the lower rates would have been allowed under the Commission's plan. This situation would arise when the total MSAC on a pipeline's system becomes greater than the amount in the pipeline's incremental gas cost account. Such a provision would allegedly protect non-exempt users from paying more under State incremental pricing plans than what they would pay under the Commission's plan.

The Commission declines to include a "no greater harm" provision in its regulations for several reasons. There is no administratively feasible method for accurately determining the amount of the monthly surcharge a non-exempt user would have paid had such a user been under the Commission's incremental pricing plan instead of a State plan. Moreover, to monitor the rates set by the States, as would be required by such a provision, would result in an additional administrative burden that would far outweigh any overall benefit that may be gained. Finally, a situation to which such a provision would apply would rarely, if ever, occur due, in part, to a recent development in the incremental pricing program. Pursuant to section 202 of the NGPA, the Commission issued a rule (Phase II rule) on May 6, 1980,[2] which, if not disapproved by either House of Congress, would have expanded the application of the incremental pricing program to other industrial uses of natural gas in addition to boiler fuel use. Because the Phase II rule was disapproved by Congress, the scope of the incremental pricing program is limited to natural gas used as boiler fuel.[3] Since the number of users absorbing the surcharges is small, it is highly unlikely that the federal incremental pricing surcharge would ever result in a non-exempt user's rate being lower than the applicable alternative fuel price ceiling.

Benefit of reduced PGA. A major concern raised in the comments arises when an interstate pipeline serves users in a State with a State incremental pricing plan as well as users in a State without such a plan. The pipeline's purchased gas cost account (PGA) is reduced by the amount of the federal incremental pricing surcharges imposed on non-exempt users served by the pipeline in the State without a State incremental pricing plan. All exempt users served by the pipeline, regardless of the State in which they are located, receive the benefit of the pipeline's reduced PGA. Several commenters suggested that the benefit of the reduced PGA be denied to exempt users in States having their own plans, because those users may already receive the benefits of the State plan. They also pointed out that the non-exempt users in States with their own plans pay no federal surcharge and, thus, do not contribute to reducing the PGA.

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[2] *Rule Required Under Section 202 of the Natural Gas Policy Act of 1978*, Docket No. RM80-10, Order No. 80, issued May 6, 1980, 45 FR 31622 (May 13, 1980).

[3] *Order Denying Rehearing and Revoking Amendments Made by Order No. 80*, Docket No. RM80-10, issued August 1, 1980, 45 FR 54741 (August 18, 1980).

The Commission does not adopt this suggestion, because such a proposal is administratively infeasible. Elimination of the reduced PGA benefit to exempt users in States having their own incremental pricing plans would require interstate pipelines to maintain separate incremental pricing accounts for each State. The burden that would be placed on pipelines and local distribution companies, in establishing the separate rates resulting from the separate accounts, and on the Commission, in monitoring such rates, would be prohibitive.

B. *State Alternatives to Incremental Pricing.* The second type of State action that appeared to have an effect on the Commission's incremental pricing program is an innovative State ratemaking plan proposed as an alternative to federal incremental pricing in that State. For instance, a State might propose to depart from the manner and method in which the surcharge under the Commission's incremental pricing plan is apportioned among the non-exempt users within the State.

Section 206(d) of the NGPA provides that the Commission may issue a rule, subject to Congressional review, which exempts from incremental pricing any appropriate category of facilities for which there is no specific statutory exemption. In the Notice in this document, the Commission preliminarily concluded that, since, by definition, such a plan would depart from the incremental pricing program mandated by Title II of the NGPA, Commission action approving such a plan would be truly exemptive in nature, and thus would be subject to Congressional review and possible disapproval under section 206(d). The Commission expressed the desire to grant States broad flexibility in seeking exemptions through alternative plans. However, it also indicated that the more an alternative plan departed from the statutory requirements of incremental pricing, the greater the scrutiny that would be applied by the Commission on review. The Notice provided that the standard for Commission approval of an alternative plan would be whether the plan advances the underlying purposes of Title II of the NGPA as well as, or better than, the Commission's incremental pricing program. The Commission proposed to consider these plans on a State-by-State basis.

All but one of the comments which addressed State alternative plans generally supported the Commission's proposal. The comment opposing the proposal argued that the proposed process for obtaining an exemption was burdensome and would result in confusing and inconsistent State proposals and Commission rulemakings.

The Commission does not find this argument persuasive. It believes that States should be given the opportunity to submit innovative ratemaking proposals to the Commission for approval as a basis for obtaining Statewide exemptions from federal incremental pricing. The Commission notes that the Statement of Managers referred to the ability of States "to provide for some form of inverted rate schedules or other ratemaking technique" designed to achieve the purposes of Title II. (S. Rep. No. 1126, 95th Cong. 2d Sess. 101 (1978)). To implement Congressional intent. State ratemaking authorities should be given as much flexibility as possible, within the mandates of Title II, to initiate innovative forms of retail ratemaking as a means to achieve the goals of incremental pricing.

By definition, an alternative plan would be inconsistent with some of the incremental pricing requirements set forth in Title II of the NGPA. For example, an inverted rate design proposal might mean that the actual average delivered price of gas to some non-exempt users at certain times would be below their alternative fuel price ceiling. This result appears to violate section 204(e) of the NGPA, at least in those cases where the surcharge imposed under the Commission's plan would raise non-exempt user rates to the alternative fuel price ceiling. Similarly, a commenter suggested that the determination of whether the price of gas to non-exempt users remained at, or above, their alternative fuel price ceiling be made on the basis of annual average rates charged to the non-exempt users. This proposal appears to violate section 204(a)(3)(A), which requires that the surcharge calculation be related to the calendar period involved, defined by the Commission to be a monthly period. (18 CFR 282.501). As another example, a commenter proposed that State regulatory agencies be allowed to establish their own alternative fuel price ceilings. This proposal appears to run contrary to section 204(e), which requires the Commission to establish these ceilings.

These proposed alternatives to incremental pricing ostensibly are inconsistent with the requirements of Title II; yet, in fact, they may further the purposes of incremental pricing as well as, or better than, the method prescribed in the Commission's regulations. At this time, the Commission takes no position as to the merits of the proposals used here as examples, but mentions them to emphasize that any State-wide exemption from federal incremental pricing based on an alternative plan would stem from the Commission's authority under section 206(d) of the NGPA.

The final rule provides that, if the Commission finds that the State alternative plan is in the public interest and achieves the underlying purposes of incremental pricing as well as, or better than, the Commission's incremental pricing program, the Commission shall issue a rule under section 206(d) of the NGPA approving the State alternative plan and specifying the extent to which natural gas used as boiler fuel by non-exempt industrial facilities subject to the alternative plan is exempt from incremental pricing. The Commission's rule approving the plan will become effective only if it is not disapproved by Congress.

Several commenters suggested that the Commission establish generic guidelines for approving alternative plans instead of considering such plans on a State-by-State basis. The Commission declines to adopt this suggestion, because the State-by-State approach gives States broader flexibility in designing alternative plans. Any submission by the Commission to the Congress under section 206(d) of the NGPA seeking broad authority to grant exemptions based on State alternative plans would have to include specific guidelines that the Commission would apply in granting exemptions under such plans. Specific guidelines can be expected to narrow the types of alternative plans presented to, and approved by, the Commission, thus reducing the desired flexibility.

Several comments advocated that the Commission limit participation in the proceeding relating to Commission consideration of an alternative plan to those persons with a direct interest in the plan. The Commission does not adopt this proposal because the alternative plan will be considered in a rulemaking proceeding in which all persons are invited to participate. Further, comments made by persons without a direct interest in a specific plan may be useful to the Commission due to the persons' experience with similar plans in other areas of the country.

C. *Miscellaneous. Rate plans of local ratemaking authorities.* One commenter pointed out that the Commission's proposal in the Notice does not provide for the situation in which retail rates are set by local municipalities rather than by the State. The commenter asserted that there is no rational or legal basis for discriminating between State and local ratemaking authorities.

The Commission agrees. Although the discussion in this rulemaking has focused on State ratemaking bodies and their authority over retail rates under Title II of the NGPA, the discussion applies equally to local retail ratemaking authorities.[4] By setting rates for non-exempt users at, or above, the alternative fuel price ceiling levels or by designing innovative rate plans as alternatives to federal incremental pricing, political subdivisions achieve the same results as State ratemaking bodies. Thus, the final regulations treat rate plans of political subdivisions, such as local municipalities, in the same manner as State rate plans.

Relation of State rate plans to Phase II rule. One commenter contended that, unless the comment period in this docket remained open until such time as the Phase II rule was issued and the outcome of the Congressional review process was known, there could be no meaningful comment on the Commission's proposals with respect to State incremental pricing plans and alternative plans. The Commission does not agree. Although the outcome of Phase II was not known prior to the February deadline for the submission of written comments, the comments nevertheless provided the Commission with meaningful guidance in promulgating this rule. In fact, most commenters assumed that a Phase II rule would not go into effect. Furthermore, insofar as the issues discussed in this order relate to the continuing legal authority of State and political subdivisions in the area of retail ratemaking in light of Title II, they are independent of the outcome of the Phase II proposal.

III. Summary of Final Regulations

The Commission's incremental pricing regulations, set forth in Part 282 of Title 18 of the Code of Federal Regulations, are amended by adding new §§ 282.104 and 282.208 and by amending § 282.504(e) (2) and (3).

New § 282.104 recognizes a State's or local municipality's authority to set retail rates and charges for natural gas to non-exempt users at, or above, the Commission's alternative fuel price ceilings. That section provides that nothing in Part 282 of the Commission's regulations precludes such action by a State or local political subdivision, or agency thereof, having authority to establish retail rates and charges for natural gas service in that State or local political subdivision.

Subparagraphs (2) and (3) of § 282.504(e) are amended to relieve natural gas suppliers of certain reporting requirements set forth in those subparagraphs. Subparagraph (2)(i) requires that a natural gas supplier respond each month to the requests of interstate pipelines, made under subparagraph (1), for the supplier's MSAC. Clause (ii) relieves the supplier of the monthly reporting requirement in clause (i), if: (1) the supplier's total monthly MSAC is zero; due to the supplier being subject to a State or local incremental pricing plan or plans; and (2) the supplier has notified the requesting interstate pipelines that the supplier is subject to such plan or plans. The purpose of the requirement that the supplier's total monthly MSAC is zero is to make clear that each of the non-exempt users served by the supplier is also subject to a State or local incremental pricing plan. If a portion of a supplier's service area is located in a jurisdiction not covered by a State or local plan, then the supplier's total MSAC would not be zero. In that case, the supplier would be required to respond under subparagraph (2)(i). In addition, the requirement that the supplier's total monthly MSAC is zero emphasizes that the supplier is relieved of the monthly reporting requirement only as long as its total monthly MSAC remains zero.

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[4] The Commission notes that NGPA section 205(e), which defines "State Commission," refers to political subdivisions.

Subparagraph (3) of § 282.504(e) is amended to provide that a natural gas supplier must report the monthly surcharge only to those customers who are required to report under subparagraph (2)(i).

New § 282.208 establishes procedures for approval of an innovative State or local ratemaking plan proposed as an alternative to the Commission's incremental pricing program.

Paragraph (a) of § 282.208 provides that natural gas used as boiler fuel by a non-exempt industrial boiler fuel facility subject to an approved State or local alternative plan shall be exempt, to the extent specified in paragraph (d), from the incremental pricing rule set forth in Part 282.

Paragraph (b) contains definitions applicable to new § 282.208. The paragraph defines the terms "State or local alternative plan," "approved State or local alternative plan," and "purposes of Title II of the NGPA."

Paragraph (c) sets forth the procedures for approval of an alternative plan. Subparagraph (1) establishes the filing requirements and provides that four copies of a request for approval and of the State or local alternative plan must be filed with the Secretary of the Commission.

Clause (i) of § 282.208(c)(2) provides that, upon receipt of the request for approval and the State or local alternative plan, the Commission shall institute a rulemaking proceeding to consider the plan. Clause (ii) states that, if the Commission determines that the alternative plan is in the public interest and carries out the purposes of Title II of the NGPA as well as, or better than, the Commission's incremental pricing program, the Commission shall issue a final rule listing the alternative plan in paragraph (d) and specifying, in paragraph (d), the extent to which natural gas used as boiler fuel by a non-exempt industrial facility subject to the alternative plan is exempt from incremental pricing.

Subparagraph (3) of § 282.208(c) provides that a final rule issued under subparagraph (2) shall be transmitted to Congress for review pursuant to section 206(d)(2) of the NGPA, and will not become effective if either House of Congress passes a Resolution of Disapproval of the rule within the thirty day review period.

Paragraph (d) contains the list of approved State or local alternative plans which is the list of State or local alternative plans approved by Commission rule and not disapproved by Congress, in accordance with paragraph (c). Paragraph (d) also specifies the extent to which facilities subject to the approved plan are exempt from the federal incremental pricing program.

IV. Effective Date

The final rule is effective October 21, 1980, in accordance with 5 U.S.C. 553(d)(1), because it establishes exemptions, and procedures for obtaining exemptions, from the Commission's incremental pricing regulations.

(Natural Gas Policy Act of 1978, Pub. L. No. 95-621, 92 Stat. 3350, 15 U.S.C. §§ 3301, *et seq.)*

In consideration of the foregoing, Part 282 of Subchapter I, Chapter I, Title 18, Code of Federal Regulations, is amended, effective October 21, 1980, as set forth below.

By the Commission.
Kenneth F. Plumb,
Secretary.

[¶ 30,201]

45 F. R. 71787 (October 30, 1980)

18 CFR Part 282

[Docket No. RM80-62; Order No. 104]

Section 206(d) Exemption for Mechanical Cogeneration Facilities From the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978

Issued: October 23, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts regulations that implement section 206(d) of the Natural Gas Policy Act of 1978 (NGPA). These rules exempt mechanical cogeneration facilities from the incremental pricing of natural gas under Title II of the NGPA. Prior to taking effect, this rule must be submitted to the Congress for review.

EFFECTIVE DATE: Thirty days after transmittal to Congress, provided that neither House of Congress passes a Resolution of Disapproval, in accordance with section 507(b) of the NGPA.

FOR FURTHER INFORMATION CONTACT:

James Liles, Office of Regulatory Analysis, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357–8158

or

Adam Wenner, Office of the General Counsel, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357–8033.

SUPPLEMENTARY INFORMATION: On May 30, 1980, the Federal Energy Regulatory Commission (Commission) issued a Notice of Proposed Rulemaking Exempting Mechanical Cogeneration Facilities from all Incremental Pricing Provisions of the Natural Gas Policy Act of 1978 (15 U.S.C. 3301 *et seq.* (NGPA).[1] This rule is intended to make available to mechanical cogeneration facilities the same exemption from incremental pricing of natural gas under Title II of the NGPA that is provided to electric cogeneration facilities.

Background

Title II of the NGPA requires that the natural gas used in certain industrial facilities be subject to incremental pricing by means of surcharges. Section 206 of the NGPA establishes certain exemptions from these incremental pricing surcharges. Section 206(c)(3) provides that incremental pricing shall not apply

> * * * to the extent provided by the Commission by rule [to] any qualifying cogenerator (as defined in section 3(18)(B) of the Federal Power Act, as amended by the Public Utility Regulatory Policies Act of 1978) [PURPA].

On September 18, 1979, the Commission issued rules implementing Title II of the NGPA and establishing a mechanism for the incremental pricing program. One provision of these rules implemented section 206(c)(3) of the NGPA for purposes of the incremental pricing program.[2] This provision exempted from the incremental pricing program all gas used for cogeneration by qualifying cogeneration facilities are defined in section 3(18)(B) of the Federal Power Act. However, at that time the Commission had not promulgated rules establishing the criteria for "qualifying cogeneration facilities" under section 3(18)(B) of the Federal Power Act. In order to facilitate the operation of the incremental pricing rules the Commission, on November 9, 1979, issued an interim rule for qualification of gas-fired cogeneration facilities for purposes of the incremental pricing program.[3] This interim rule established an exemption from incremental pricing for certain cogeneration facilities which were in existence and used natural gas as an energy input on or prior to November 1, 1979.[4]

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[1] 45 FR 38080 (June 6, 1980).

[2] 18 CFR 282.202(e), 44 FR 37726 (October 5, 1979).

[3] Docket No. RM79-54, issued November 9, 1979, 44 FR 65744 (November 15, 1979).

On March 13, 1980, the Commission issued a final rule under section 201 of PURPA establishing requirements for a determination of qualifying status for small power production and cogeneration facilities.[5] This rule maintained the criteria for the exemption from incremental pricing established in the interim rule, and also established additional criteria for other facilities not previously eligible [6] for the exemptions from incremental pricing set forth in 18 CFR 282.202(e).

The application of these exemptions, however, is limited by section 3(18)(B) of the Federal Power Act to cogeneration facilities which produce *electric* energy, and other forms of useful energy. Cogeneration facilities which produce *mechanical* energy and other forms of useful energy are not eligible under the final rule in Docket No. RM79-54 for these exemptions from incremental pricing.

Mechanical cogeneration facilities can produce the same fuel efficiencies as can cogeneration facilities producing electric energy. The proposed rules reflected the Commission's belief that cogeneration facilities which produce mechanical energy should be afforded the same exemption from incremental pricing surcharges as is available to cogeneration facilities which generate electricity. Section 206(d) of the NGPA authorizes the Commission to exempt from incremental pricing "any other industrial facility or category thereof." The proposed rule represented an attempt to utilize this authority to place mechanical and electrical cogeneration on an equal footing vis-a-vis the exemption from incremental pricing. Any rule providing for an exemption by the Commission under section 206(d) is subject to Congressional review before it can become effective.

The Basis for a Section 206(d) Exemption

Cogeneration involves the production of both useful heat and power through the sequential use of energy. Shaft power, compressed air and hydraulic power are all variations of the high-grade energy form known as mechanical power or energy. Production of any of these mechanical energy forms, with utilization of the reject heat from a facility, represents energy-efficient cogeneration with an energy conservation potential similar to that available from cogeneration involving the production of electricity.

The incentive provided through the exemption of cogeneration from incremental pricing is intended to promote the efficient use of energy by cogeneration facilities. However, as noted, under the existing rules, only those cogeneration facilities which generate electricity are eligible for the exemption; those producing only mechanical power are excluded. Not only is this distinction inequitable, since energy resources may be conserved absent electrical generation, but it may create a significant incentive for needless capital investment. An industrial company with a need for mechanical power which could be obtained through cogeneration might have an economic incentive through lower natural gas prices to cogenerate electrical instead of mechanical power. This electricity would, in turn, be used to power electric motors, which would be used to drive the machinery. Thus, several intermediate steps would be taken to obtain mechanical power.

The expense of installing the generators and motors would be needlessly incurred, since the cogeneration prime mover could directly supply the required mechanical power. Moreover, the intermediate conversion to electricity would result in energy losses since motors and generators are always less than perfectly efficient. By making mechanical cogeneration facilities eligible for the exemption from incremental pricing, this rule would remove this incentive to install unneeded equipment.

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[4] 18 CFR 282.501-282.503, 44 FR 65744 (November 15, 1979).

[5] Order No. 70, issued March 13, 1980 in Docket No. RM79-54, "Final Rule Establishing Requirements and Procedures for a Determination of Qualifying Status for Small Power Production and Cogeneration Facilities," 45 FR 17959 (March 20, 1980).

[6] 18 CFR 292.205(c).

In the proposed rule, the Commission emphasized that this rule will not affect any of the provisions of Order Nos. 69 or 70 which pertain to electrical cogeneration.[7] The final rule does, however, adopt certain terms and criteria similar to those used in Order No. 70 for qualifying electrical cogeneration facilities. In order to ensure that mechanical and electrical cogeneration facilities are afforded similar treatment under the incremental pricing provisions of the NGPA, the efficiency standards adopted are similar to those prescribed for electrical cogeneration facilities in Order No. 70.

Summary of Comments

The Commission received thirteen comments to the proposed rule.[8] A public hearing, scheduled for July 1, 1980, was cancelled due to lack of public response. All of the thirteen comments expressed general support for the proposed rule; eight comments offered specific recommendations for revisions.

Measurement of Mechanical Power and Related Issues

The proposed rule provided that the useful mechanical power output of a cogeneration facility could be determined at the output of the prime mover—or at some further stage of energy conversion, at the discretion of the cogenerator. Comments were requested as to whether the term "output of the prime mover" is appropriate, and whether the determination of mechanical power output should be permissive in regard to the point of measurement. Comments were also requested on the feasibility of measuring mechanical power output.

Seven commenters addressed the related issue of mechanical power measurement.[9] To varying degrees, these commenters suggested that ongoing measurement of the mechanical power output of an engine is generally infeasible. The commenters requested that the proposed requirement for measurement of mechanical power be replaced with a requirement that mechanical power be estimated. The Commission believes that these requests have merit, and adopts this recommendation.

Since a calculation which is appropriate for one cogeneration facility may be unsuitable for another, the rules do not specify a specific mechanical estimation technique. Rather, calculations are to be based on standard engineering methods, and must reflect the calendar year period specified for the operating and efficiency standards. The location of the estimate is within the discretion of the cogenerator. Calculations may be based on the design characteristics of the prime mover, the equipment driven by the prime mover, or on actual measurements.

NI-Gas requested a more specific definition of the term "prime mover." This commenter believed that the proposed rule was unclear as to whether, for example, a steam turbine or the boiler supplying steam to the turbine is the prime mover. A prime mover is a device which converts other forms of energy (such as thermal energy or chemical energy) into mechanical energy. The Commission is mindful, however, that any simple definition of such a fundamental concept may work to exclude some novel technology or innovation. The Commission has, therefore, decided not to add a definition of "prime mover" to the rules. Instead, the phrase "* * * at the output of the prime mover * * * " has been modified to read "* * * at the output of the steam turbine, combustion turbine, or other prime mover * * *." This change will serve to clarify the intent without running the risk of an overly narrow definition. Thus, in the NI-Gas example, the prime mover is the steam turbine.

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[7] Order No. 69, 45 FR 12214 (February 25, 1980), and Order No. 70, 45 FR 17959 (March 20, 1980).

[8] American Cyanamid Company, American Paper Institute (API), Chemical Manufacturers Association (CMA), The Dow Chemical Company, Glass Packaging Institute (GPI), Masonite Corporation (Masonite), Monsanto Company, Northern Illinois Gas Company (NI-Gas), Potlatch Corporation (Potlatch), Republic Steel Corporation, The Standard Oil Company (SOHIO), Stauffer Chemical Company, and Sun Petroleum Products Company (Sun Petroleum).

[9] API, CMA, Masonite, NI-Gas, Potlatch, SOHIO, and Sun Petroleum.

Revised Language

Several commenters requested clarification of certain portions of the proposed rules, and offered alternative language. The American Paper Institute [APA] suggested that the statement of the operating and efficiency standards in § 282.211(c) be combined. With regard to rules on electrical cogeneration facilities, an operating standard was adopted for topping-cycle systems to ensure that *bona fide* cogeneration situation exists. Efficiency standards were adopted for topping-cycle systems using oil or gas to ensure efficient use of these scarce fuels. Exemption from incremental pricing is available to electrical cogeneration facilities only if both operating and efficiency standards are met. Since the Commission's sole concern with mechanical cogeneration facilities in this docket is exemption from incremental pricing—and the Commission has decided to afford the exemption to mechanical facilities on the same basis as electrical facilities—both operating and efficiency standards must be met in order for a mechanical cogeneration facility to qualify for an exemption. Since both standards are applicable in all cases, the Commission will accept API's recommendation and simplify the statement of the standards.

Technical Definitions

NI-Gas commented on the definition of mechanical cogeneration facility. The definition in the proposed rule limited the term "useful thermal energy" to energy "used for industrial or commercial heating or cooling purposes * * *." The definition of cogeneration facility in Order No. 70 is less restrictive. In that definition, the useful thermal energy must be "used for industrial, commercial, heating, or cooling purposes * * *." Each term—industrial, commercial, heating, and cooling—stands alone. Under this definition, the useful thermal energy may be used in an industrial (or commercial) process other than heating or cooling. Process steam, for example, may be used directly in a chemical reaction. Heating or cooling purposes which are neither industrial nor commercial are also permitted under the definition in Order No. 70. Residential heating uses, for example, would be included. NI-Gas recommends that the less restrictive language found in Order No. 70 be used to define a mechanical cogeneration facility. The Commission has adopted this recommendation.

NI-Gas also recommended that the definitions of mechanical cogeneration facility and supplementary firing be modified to indicate that only facilities covered by Phase I of incremental pricing are included. As mandated under Title II of the NGPA, the Commission is required to implement the incremental pricing program in two phases. The Phase I rules apply only to the use of natural gas by large industrial boiler fuel facilities. On May 7, 1980, the Commission issued Phase II rules in Docket No. RM80-10 expanding the scope of the incremental pricing program to other industrial uses of natural gas. This Phase II rule was submitted to Congress for a mandatory review prior to taking effect. On May 20, 1980, the House of Representatives passed a Resolution of Disapproval, and the Commission has since vacated its

Phase II Order.[19] Therefore, only natural gas used as boiler fuel by large industrial facilities is now subject to incremental pricing. Both of NI-Gas's recommended modifications would explicitly restrict the definitions of mechanical cogeneration facility and supplementary firing to boiler fuel use of gas which is not otherwise exempt from incremental pricing. NI-Gas proposes these changes as an effort to "avoid needless confusion."

The Commission has decided not to adopt the recommended changes. The Commission believes that these recommendations would be likely to cause confusion at the end-user level. On the one hand, the definitions of basic terms would become strikingly different when applied to electrical or mechanical cogeneration facilities. Many end-users have both types of cogeneration in the same plant. On the other hand, the recommendations would make the definitions contingent upon the status of other exemptions, such as the agricultural use exemption.

Since other exemptions are themselves contingent upon various circumstances (alternative fuel tests or monthly gas consumption, for example) confusion would likely arise concerning the timing for filing for an exemption, and the time when such exemption would become effective. Moreover, future consideration of a second Phase II rule would likely require that the definitions of mechanical cogeneration facility and supplementary firing be substantially modified and expanded. On balance, the Commission does not believe that end-users who are not presently subject to incremental pricing will be confused by promulgation of an exemption in broad inclusive language.

The Glass Packaging Institute (GPI) recommends an expansion of the definition of cogeneration to include facilities in which no mechanical or electrical energy is produced. Certain energy conversion systems, while not producing electrical or mechanical energy, may displace the need for such energy. The example cited by GPI is a system in which reject thermal energy from an industrial process is used in an adsorption refrigeration unit rather than a bottoming-cycle mechanical drive. GPI claims that the absorption system displaces a requirement for electrical or mechanical power and, therefore, the entire system should be considered the functional equivalent of a cogeneration facility.

The Commission recognizes that a facility such as that described by GPI could be highly energy efficient. However, GPI's proposal would be difficult if not impossible to administer. The efficiency of a non-mechanical "cogeneration facility" would have to be determined on the basis of a hypothetical displaced system. Any such evaluation of *what might have been* rather than *what is* leaves room for serious differences of opinion. GPI mentions the possibility that a cogeneration use might be claimed where thermal output from a "bottoming-cycle" is used simply for space heating. GPI states that this situation could be expressly excluded by not allowing the displacement of electric resistance heating. But the owner of such a system could reasonably claim that an electric heat pump was displaced—much the same as GPI's example facility displaces an electric air conditioning unit. There would be no straightforward way to resolve such a dispute. For these reasons, the Commission has decided not to adopt GPI's recommendation. However, it notes that the facility described by GPI would not be subject to incremental pricing under the Phase I rule since it does not use natural gas as boiler fuel.

Efficiency Standards

The Masonite Corporation (Masonite) recommends that lower efficiency standards be used for qualification of mechanical power facilities than were used for electrical cogeneration facilities. Masonite suggests that the proposed 42.5 percent test set forth in § 282.209(b) (§ 282.211(c) in the proposed rule) be reduced to 36.5 percent. No recommendation is made concerning the 45 percent efficiency requirement for cogeneration facilities with less than 15 percent of total energy output in the form of thermal energy.

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[19] Order Denying Rehearing and Revoking Amendments made by Order No. 80, issued August 1, 1980, in Docket No. RM80-10, 45 FR——(August ——, 1980).

Masonite states that the Commission is "essentially ignoring the losses which occur between the electrical generator source and the end user." An example is given of two equivalent pump systems, one mechanical and the other driven by an electric motor receiving its power from an electrical cogeneration facility. Masonite explains that the electrical cogeneration facility would have to be sized larger than the mechanical system to account for "electrical transformation and transmission line losses * * * as well as power losses in the electrical motor." In order to adjust for such power losses, lower efficiency standards are recommended for the mechanical system.

Masonite is correct in recognizing that the Commission's rules ignore losses which occur between a generator and ultimate user of electricity. In this regard, in the preamble to the proposed rule, the Commission stated:

> The proposed rule does not require theoretical conversion of mechanical energy to an electrical energy equivalent. A cogenerator developing only mechanical power most probably desires this form of energy for use in his facility. It is appropriate to relate this mechanical energy to an equivalent efficiency standard, rather than to attempt a determination of what quantity of electricity could reasonable be generated from the cogenerator's mechanical power.[11]

The converse is equally true. The rule does not attempt to require determination of the quantity of electricity that would be necessary to serve a mechanical load. A cogenerator is presumed to produce energy in the form desired. The fact that other, hypothetical systems may be less efficient should not affect the qualification of an actual system. As a matter of policy, the Commission believes that cogeneration facilities producing either electrical or mechancial power output should be measured against a common standard of efficiency.

Multiple Steam Turbines

Two commenters, Masonite and SOHIO, made similar recommendations concerning the aggregation of cogeneration units at the same site.

Masonite points out that turbines used for producing mechanical energy "are quite often smaller and more numerous in use at a site than those turbines driving electrical generators * * *" Both commenters suggest that aggregation of multiple mechanical power turbines at a single site be allowed for purposes of qualifying under the rules. SOHIO recommends that a plant with four or more prime movers or heating loads be permitted to qualify based on an overall plant steam balance.

SOHIO argues that a plant with many individual pieces of equipment "would not have the instrumentation required to measure power production, or the total hearing load." The question of how mechanical energy may be measured has been addressed elsewhere. Meters and gauges are not required. A plant with many small turbines should not incur any extra cost of instrumentation.

Under the Commission's definition of "mechanical cogeneration facility"[12] a group of turbines may be considered as a single unit for purposes of the rule if each draws steam from, and exhausts steam to, common steam headers. In this situation, all of the turbines occupy the same position in the "cascade" of energy through a sequential process.

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[11] 45 FR 38081 (June 6, 1980).

[12] Section 282.209(a)(1) (§ 282.211(a)(1) in the proposed rule) defines a "mechanical cogeneration facility" as equipment used to produce mechanical energy and forms of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes, through the sequential use of energy. . . .

However, the Commission chooses not to adopt a rule which would allow an entire industrial plant to qualify for exemption on the basis of an overall steam balance. The purpose of this rule is to afford an exemption from incremental pricing to gas-fired cogeneration. The rule is not intended to exempt an entire industrial boiler fuel facility from incremental pricing on the grounds that the plant contains certain cogeneration applications. Only the cogeneration applications are eligible for exemption under this rule.

In the comments, SOHIO provided a diagram of an industrial facility containing a variety of backpressure and extraction steam turbines. This facility also contained an unspecified block of "heating and non-heating loads" served directly from the boiler and not part of any sequential use of energy. Such steam loads were considered by the Commission previously in promulgating rules under section 201 of PURPA.[13] In the preamble to those rules, the Commission stated:

> * * * many industries commonly route steam directly from their boilers to processes without expansion in a turbine. This practice is simply the raising of process steam; it is not cogeneration. The fact that some other steam from the same boiler is routed to cogeneration equipment does not mean that all steam from the boiler is used for cogeneration. The coincident raising of process steam relates to the cogeneration rules in two ways. First, any energy expended in raising such steam should not be entered into any efficiency calculations. Secondly, natural gas used for raising process steam is not rendered exempt from incremental pricing solely because the boiler may also supply steam for cogeneration.

The Commission further wishes to amplify that condensing mechanical drive turbines served directly from a boiler do not comprise cogeneration since there is no sequential use of energy.

Moreover, any topping-cycle mechanical cogeneration facility must meet the five percent useful thermal output standard under § 282.209(b) in order to qualify for exemption from incremental pricing. The standard requires that no less than five percent of the total energy output, during any calendar year period, be in the form of useful thermal energy. Thus a plant containing only mechanical drive and other non-thermal use of steam does not meet the requirement. This holding is analogous to the Commission's treatment of combined-cycle electric generation facilities under Order No. 70.[14]

Congressional Review and Effective Date

The rule set forth below is issued pursuant to section 206(d) of the NGPA. That section requires that such rule be submitted to the Congress for review prior to taking effect. After submission to each House of Congress, the rule may take effect following 30 days of continuous session of Congress (as set forth in subsection 507(b) of the NGPA) unless either House adopts a resolution of disapproval within that 30 day period. Accordingly, this rule will be effective on the day following expiration of the 30-day period for Congressional review.

In consideration of the foregoing, if neither House of Congress passes a Resolution of Disapproval of the regulations transmitted to them in this rulemaking within 30 days of Congressional review, as determined in accordance with section 507(b) of the NGPA, Part 282 of Subchapter I, Chapter 1, Title 18, Code of Federal Regulations, is amended as set forth below, effective on the day following expiration of the 30-day Congressional review period.

(Natural Gas Policy Act of 1978, Pub. L. No. 95-621, 92 Stat. 3350, 15 U.S.C. §§ 3301-3434)

By the Commission.

Kenneth F. Plumb,
Secretary.

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[13] Docket No. RM79-54. Order No. 70, 45 FR 17961.

[14] 45 FR 17959, 17961 (March 20, 1980).

[¶ 30,202]

45 F. R. 73027 (November 4, 1980)

18 CFR Parts 270, 271

[Docket No. RM80-53]

Order of the Director, OPPR of Publication of Maximum Lawful Prices Under Title I of the NGPA

October 27, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: Pursuant to the authority delegated by 18 CFR 375.307(1), the Director of the Office of Pipeline and Producer Regulation revises and publishes the maximum lawful prices prescribed under Title I of the NGPA. Section 101(b)(6) of the NGPA requires that the Commission compute and publish maximum lawful prices under Title I at the beginning of each month for which such figures apply.

EFFECTIVE DATE: October 27, 1980.

FOR FURTHER INFORMATION CONTACT: Kenneth A. Williams, Federal Energy Regulatory Commission, 825 N. Capitol Street, N.E., Washington, D.C. 20426, (202)-357-8500.

Section 101(b)(6) of the NGPA requires that the Commission compute and make available maximum lawful prices prescribed in Title I and inflation adjustments before the beginning of any month for which such figures apply.

Pursuant to that mandate and pursuant to § 375.307(1) of the Commission's regulations, delegating the publication of such prices and inflation adjustments to the Director of the Office of Pipeline and Producer Regulation, the maximum lawful prices for the months of November and December, 1980 and January 1981, are issued by the publication of price tables for the applicable quarter. Pricing tables may be found in § 271.101(a) of the Commission's regulations. Table I of § 271.101(a) specifies the maximum lawful prices for gas subject to sections 102, 103, 106(b)(1)(B), 107(c)(1), 107(c)(5), 108 and 109 of the NGPA. Table II of § 271.101(a) specifies the maximum lawful prices for sections 104 and 106(a); Table III of § 271.102(a) sets forth the inflation adjustment.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

[¶ 30,203]

45 F. R. 75192 (November 14, 1980)

18 CFR Part 260

Interim Rule Revising Annual Report of Gas Supply for Certain Natural Gas Pipelines; Form No. 15

Issued November 6, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Interim rule.

SUMMARY: By this interim rule, the Federal Energy Regulatory Commission amends Form No. 15, Annual Report of Gas Supply for Certain Natural Gas Pipelines, to eliminate reporting requirements which the Commission no longer needs to carry out its regulatory functions. This interim rule will be effective for reports covering calendar year 1980 and subsequent calendar years, until certain issues relating to proposed further changes in the content, format and instructions of Form No. 15, are resolved. The changes are a product of the Commission's ongoing effort to eliminate unnecessary reporting burdens and to update its forms.

EFFECTIVE DATE: November 6, 1980.

FOR FURTHER INFORMATION CONTACT: Wayne Thompson, Chief, Gas Supply Branch, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Room 4402-B, Washington, D.C. 20426, (202) 357-9077.

A. Background

Form No. 15, Annual Report of Gas Supply for Certain Natural Gas Pipelines, was instituted to obtain an annual report of the total gas supply of each pipeline company under the jurisdiction of the Federal Power Commission (Commission).[1] This gas supply reporting requirement—which continues today under this Commission's authority—covers each interstate pipeline company's owned reserves, producer contracts for which the producer has received a certificate to sell the gas to the pipeline,[2] gas purchase contracts with other jurisdictional pipelines,[3] purchases of gas from foreign suppliers, purchases of Liquefied Natural Gas (LNG), Synthetic Natural Gas (SNG),[4] and short-term or other purchases over which the Commission has regulatory authority.

Form No. 15 provides the Commission with information needed to address gas supply issues in certificate applications, to perform depreciation analyses in rate cases, and to make determinations concerning new or increased sales, the extension of facilities, or the abandonment of services.

On August 7, 1980, the Commission issued a Notice of Proposed Rulemaking to revise Form No. 15 (45 FR 54082, August 14, 1980), as part of its program to review the collection of data which the Commission uses for making decisions in the regulatory process. The rulemaking proposed to amend the content, format, and instructions of Form No. 15 in order to make the form more concise, better facilitate its use, and reduce unnecessary respondent reporting burdens. The schedules were to be redesignated to better facilitate completion by hand, and definitions and data requests were to be standardized and made to conform with changes resulting from passage of the Natural Gas Policy Act (NGPA). The changes were proposed to be implemented in time for the report due on April 1, 1981, which covers gas supplies during the 1980 calendar year period.

B. Analysis of Comments.

In response to the Notice of Proposed Rulemaking, the Commission received fourteen comments from sixteen parties.[5] Of these, twelve were from interstate pipelines which are required to file the form,[6] one was from a natural gas user, and one was from an industry association.

1. *Format Revisions*

In general, the commenters supported the Commission's intention to reduce reporting burdens through the deletion of certain data items in Form No. 15.[7] However, the reaction was almost universal that the revised format, content, and instructions would actually result, initially, in an *increased* burden to respondents. Among the specific complaints was that the Commission indicated that it would prefer that respondents file a magnetic tape (computer copy) of the form in the current format, as well as a "hard copy" (computer printout) in the proposed format. Commenters argued that this "dual system" would be duplicative and that it would be expensive to devise and maintain. Furthermore, it would be impossible to reprogram computers pursuant to the new format, instructions and contents in time for the April 1, 1981 filing.

A suggestion was made to simply retain Form No. 15 with its present format and instructions because that would be less burdensome than the proposal. Another proposed that a revised form should become effective in time to be filed by April 1, 1982.

Comments also alleged that revisions in the instructions as a result of clarifications and changes to conform with recently-passed legislation, created greater reporting requirement—in conflict with the Commission's purpose to lessen the reporting burden. Some commenters also alleged that certain of the definitions were inconsistent with each other as a result of the proposed revisions.

Because various problems arose with respect to the proposed format changes to Form No. 15, the Commission has determined that extensive revision of Form No. 15 would be inappropriate at this time. However, the Commission is satisfied that certain information described below, should be eliminated immediately. Therefore, for the present, Form No. 15 is revised only insofar as those items originally proposed for deletion will be eliminated; no new instructions, clarifications, reformatting or other requirements are imposed by these amendments.[8] Further changes will be considered in the near future. At time further public comment will be solicited.

2. *Deletion of Reporting Requirements.*

General Motors Corporation (GM) opposed the deletion of reporting requirements in Form No. 15. In general, GM noted the importance of the Commission's collecting and considering reliable data on future gas supplies and deliveries. GM urged that no important information be omitted, that clarification of data be provided where necessary and that new information be collected where it would be useful. Specifically, GM suggested that the 20 year annual projection of total pipeline system gas requirements (Schedule 1) be retained instead of the one year of requirements data to be reported under the proposed rule. In addition, the proposed elimination of curtailment data for the current report year was, according to GM, unexplained and undesirable. Finally, GM suggested several additional reporting requirements for the form.

The Commission believes that the 20 year annual projection of total pipeline system gas requirements should not be retained. Because of gas shortages, effects of conservation, fuel switching and fluctuations in the weather, total annual requirements are rarely fulfilled; therefore, the direct relevance of the reporting of annual requirements has become limited. In addition, the long-term projection of requirements data tends to be inaccurate. Finally, pipeline system requirements data are now reported in Schedule I of FERC Form No. 16 (*see* 18 CFR § 260.12), and the requirements profile of jurisdictional companies has been developed in the "Omnibus" proceedings (Docket No. TC80-60, *et al.*, September, 1980). The Commission considers this information to be sufficient to evaluate jurisdictional company requirements.

Finally, the Commission has eliminated the requirement to report curtailment data during the report year in Schedule No. 1 of Form No. 15 because this information is available in greater detail in the Commission's Form No. 16 (revised May 30, 1980. Order No. 88, RM80-20, 45 *FR* 37812, June 5, 1980).

3. *Informal Conferences.*

Commentors generally suggested that the Commission should not make extensive changes to the format or instructions to Form No. 15 until informal conferences have been held between interested members of the public and the Commission to discuss problems regarding contemplated changes. As noted above, the amendments made in this interim rule do not include any of the proposed changes to the format. The Commission does intend to further consider such changes in the forthcoming weeks. Interested persons are invited to a series of conference meetings with Commission staff beginning in early December in order to discuss and revise Form No. 15 in the light of legal, regulatory and industry considerations. An announcement specifying the dates and times of these meetings will be issued in the near future.

A final rule, to further amend Form No. 15, will be issued subsequent to the above-mentioned conference meetings.

C. Revisions to Form 15.

Form 15 is revised by deleting the following requirements:

General. The requirement to report "Class Code" on each statement and schedule is deleted. Also eliminated is the requirement to file individual reservoir area outline maps.

Statements. In the first substantive statement, "Synopsis of Pipeline Company Gas Supply" (p. 0047), items 04 through 10 which pertain to information from the last certificate application are deleted because they are available elsewhere.

Schedules. The following items in Schedule Nos. 1 through 4 are deleted:

Schedule No. 1, "System Deliverability Summary".

Entry Nos. 104–122—Annual Requirements Curtailments.

Entry No. 123—Total Volumes Scheduled (Annual Requirements)*

Entry No. 125—Firm Gas Sales Interruptible Gas Sales Other use Gas Reserve Life Index.

Schedule No. 2, "Reservoir Data and Dedicated Remaining Recoverable Salable Reserves".

Line No. 1—FPC Natural Gas Area.

Line No. 2—Type Calculation, Total-Producing Completions, Total Net Completions, Dedicated Percentage of Sellers Reserves, Decline Factor MMcf Per PSI, Cumulative Wet Gas Production at Current Pressure, Current Z Value, Terminal Z Value, Depth Classification, Basic Lithology.

Line No. 4—Recovery Factor, Productive Area—Acres, Average Net Thickness—Feet Reservoir Volume—Acre/Feet, Porosity, Porosity By (How porosity is determined), Connate Water, Connate Water By (How connate water is determined), Initial Z Value, Yield, Barrels Per MMcf, Mole Percent H_2S, Mole Percent N_2, Mole Percent CO_2, Initial Formation Volume Factor (FVF).

Schedule No. 3, "Deliverability Estimate For Each Supply Source".

Line No. 2—All Data Elements

Line No. 3—Pc (Shut-in pressure), Pt (Flowing pressure), Pf (Formation pressure), Ps (Sandface pressure), C (Coefficient C in back pressure equation), n (value of slope n), Q (rate of flow), Duration Flow, Wellhead Open Flow, Absolute Open Flow, Daily Productive Capacity—Non-Associated Gas, Daily Productive Capacty—Associated and Solution Gas, Gas Volume Not Scheduled*

Line No. 4—Net Completions*

Schedule No. 4, "Committed Reserves and Deliverability Estimates for Other Supply Sources".

Line No. 1—FPC Natural Gas Area.

Line No. 2—Pipeline Code*, Seller Code*, Daily Productive Capacity for Undesignated Gas, Daily Productive Capacity for Non-Associated Gas, Daily Productive Capacity for Associated and Solution Gas, Volume Curtailed, MMcf*

Line No. 3—Gas Volume Not Scheduled.

The form, as revised by this Interim Rule, shall be filed on or before April 1 for each calendar year ending December 31 of the previous year as is currently required, beginning with April 1, 1981.

In addition, the Commission has sent a memorandum to the Energy Information Administration (EIA) (*see.* Attachment B to the document) [9] regarding clarification of the instructions for Form No. 15.

D. Public Procedure and Effective Date.

The Commission has complied with 5 U.S.C. § 553 by having provided the public with notice and an opportunity to participate in this rulemaking. Immediate adoption of the revisions to Form No. 15 will promote an expeditious reduction of unnecessary reporting burdens. Therefore, under 5 U.S.C. § 553(d), the Commission is making these changes effective immediately for reports covering calendar year 1980, to be filed on or before April 1, 1981.

(Administrative Procedure Act, 5 U.S.C. § 553; Natural Gas Act, 15 U.S.C. §§ 717–717w; Department of Energy Organization Act, 42 U.S.C. §§ 7101–7352; E.O. 12009, 42 FR 46267; Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301–3432.)

For the foregoing reasons, FPC Form No. 15, is revised as set forth in Attachment A to this Interim Rule, and Part 260 of Chapter I, Title 18 of the Code of Federal Regulations is amended as set forth below, effective immediately as an interim rule.

By the Commission.

Kenneth F. Plumb,

Secretary.

—Footnotes—

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[1] Form No. 15 was initially promulgated in 1964: Order No. 279, Docket No. R–230, 29 FR 4874 (April 7, 1964). It has undergone four revisions since that date: Order No. 337, Docket No. R–308, 32 FR 3282 (February 25, 1967), revised the form to allow companies with comparatively small volumes of reserves to file an abbreviated report, and made certain conforming amendments; Order No. 399, Docket No. R–308, 35 FR 6962 (May 1, 1970), amended the form to require respondents to submit estimates of productive capacity Mcf/day, maximum daily quantity Mcf/day for each source of gas supply, and gas reserves by independent

producer rate schedules, and made other minor changes; Order No. 476, Docket No. R-308, 38 FR 6810 (March 13, 1973), amended the form with reference to the reserves report; and Order No. 546, Docket No. R-308, 41 FR 9866 (March 8, 1976), revised the form to require that respondents disclose gas reserves filings with other Federal agencies.

[2] Pursuant to the Natural Gas Policy Act (NGPA), producers are no longer required to obtain certificates in certain instances. (*See* sections 302, 312, and 601 of the NGPA.)

[3] We note that pursuant to the NGPA, pipelines are also permitted to purchase gas from intrastate pipeline companies. (*See* sections 302, 303, 311, and 601 of the NPGA.)

[4] Also known as "Substitute" Natural Gas.

[5] Columbia Gas Transmission Corporation, El Paso Natural Gas Company, Michigan Wisconsin Pipe Line Company, Natural Gas Pipeline Company of America, Northern Natural Gas Company, Panhandle Eastern Pipe Line Company and Trunkline Gas Company, Southern Natural Gas Company, Tennessee Gas Pipeline Company, Texas Eastern Transmission Corporation and Transwestern Pipeline Company, Texas Gas Transmission Corporation, Transcontinental Gas Pipe Line Corporation, United Gas Pipe Line Company, General Motors Corporation and Interstate Natural Gas Association of America.

[6] A total of 93 interstate gas pipelines are currently required to file Form No. 15.

[7] Most comments were in agreement with respect to the Commission's proposed deletions of data items.

[8] Companies filing computerized versions of the Form No. 15 may submit it in the current format, retaining the items deleted herein to alleviate the burden of reprogramming.

[9] Item inadvertently omitted from the Preamble to the Notice of Proposed Rulemaking—deletion of this item was noted in the schedule attached to the notice.

[10] Items inadvertently omitted in the Preamble to the Notice of Proposed Rulemaking—deletion of these items was noted in the schedules attached to the Notice.

[11] The memorandum sent to EIA and revised Form No. 15 (Attachment A) are not being printed by the Federal Register. Copies are available in the Commission's Office of Public Information.

[¶ 30,204]

45 F. R. 76115 (November 18, 1980); 45 F. R. 77420 (November 24, 1980)

18 CFR Parts 4 and 375

[Docket No. RM80-65; Order No. 106]

Exemption From All or Part of Part I of the Federal Power Act of Small Hydroelectric Power Projects With an Installed Capacity of Five Megawatts or Less

Issued: November 7, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission adopts procedures to exempt from all or some of the requirements of Part I of the Federal Power Act, including licensing, small hydroelectric power projects with a proposed installed capacity of 5 megawatts or less. The final rule constitutes a means of evaluating such projects for exemption on a case-by-case basis and is the first action undertaken to implement section 408 of the Energy Security Act of 1980. The statute also gives the Commission discretion to exempt classes or categories of small hydroelectric power projects.

Only projects with a generating capacity of 5 megawatts or less, including new capacity that must be developed in order to qualify a project for exemption, may be exempted. These projects must utilize the water power potential of an existing dam or a natural water feature, without the need for a dam or impoundment. The rule sets forth who may apply for exemption, how to apply, and how any conflicts between an exemption application and any other kind of application to develop a project will be resolved.

The final rule is designed to encourage the development of small hydropower facilities by providing a method of relieving them from certain regulatory requirements.

EFFECTIVE DATE: November 7, 1980.

FOR FURTHER INFORMATION CONTACT:

Ronald A. Corso, Director, Division of Hydropower Licensing, Office of Electric Power Regulation, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357–3507/5321;

Howard A. Jack, Assistant General Counsel for Hydroelectric Licensing, Office of the General Counsel, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357–8448;

James H. Hoecker, Division of Regulatory Development, Office of the General Counsel, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357–9342.

The Federal Energy Regulatory Commission (Commission) establishes procedures for exempting from all or part of Part I of the Federal Power Act (Act) certain small hydroelectric power projects (projects) having a proposed installed generating capacity of 5 megawatts or less. The rule implements in part section 408 of the Energy Security Act of 1980 (ESA).[1] The Commission will provide such exemptions based on case-by-case determinations and will consider further rulemakings to exempt classes or categories of projects, as permitted by section 408(b) of the ESA. The final rule is effective November 7, 1980.

I. Background

Title IV of the ESA, also known as the Renewable Energy Resource Act of 1980, contains a provision that amends the Public Utility Regulatory Policies Act of 1978 (PURPA) to authorize the Commission to exempt certain small hydroelectric power projects, on a case-by-case basis or by class or category of such projects, from all or part of Part I of the Act, including any licensing requirement.

Section 408 grants the Commission discretion to provide exemption under the following specified conditions. The proposed installed capacity of an exemptible project may not exceed 5 megawatts. To be exemptible, a project must utilize the water power potential of an existing dam, unless it is a project that will utilize a so-called "natural water feature" that does not require the creation of a dam or man-made impoundment. Such a natural water feature will commonly be an elevated lake or a waterway the topographical features of which permit diversion of some waters for purposes of power generation. Finally, section 408 provides that certain environmental requirements apply to those projects that the Commission exempts from licensing. Those requirements include the National Environmental Policy Act, the Fish and Wildlife Coordination Act, the

Endangered Species Act, and the consultation provisions in section 30 of the Federal Power Act that apply to exemption of small conduit hydroelectric facilities.

The Notice of Proposed Rulemaking in this docket was issued for public comment on August 28, 1980.[2] Prior to issuing the proposed rule, the Commission issued a Notice of the Availability of a Draft Rule and of Informal Conferences.[3] Pursuant to that notice, the Commission's staff took informal comments on the draft rule and related inquiries and held informal conferences on them in Washington, D.C. on August 1, 1980 and August 12, 1980. In addition to requesting written comments on the rule as finally proposed, the Commission held a third public meeting to discuss the rule, on September 23, 1980. The comments, including transcripts of the three meetings, are available for inspection in the public files of the Commission.

This phase of the implementation of section 408 of the ESA utilizes case-by-case determinations based on information provided by individual applicants to provide exemptions for small hydroelectric power projects.[4] The Commission will exempt small hydroelectric power projects in much the same way it now exempts small conduit hydroelectric facilities.[5]

This exemption rule has several important features. First, only a person who has sufficient property interests to develop a small hydroelectric power project may apply for exemption. Second, a project owner may apply for exemption from licensing or from any of the other provisions of Part I of the Act, but application procedures for each of these two kinds of exemption differ. Third, all, but not part, of a currently licensed water power project is exemptible. Fourth, the rule explains in detail a system of priorities and preferences among the various kinds of applicants that seek to develop a project. Finally, an applicant may seek, consistent with the statute, waiver of any provision of the rule.

II. Comment Analysis

Two related issues received the most extensive commentary. The proposed rule permitted only a project owner, *i.e.*, someone with a real property interest sufficient to develop the project, to apply for exemption and provided that exemption applications timely filed will be preferred to applications for preliminary permit or, all other things being equal, for license. The proposed rule, had the effect of eliminating the preference that section 7(a) of the Act would afford a non-owner state or municipality that applies for a license or preliminary permit insofar as such applicant competes with an accepted application for exemption. Instead, the proposed rule provided project owners a priority over non-owners, regardless of state or municipal status.

Municipalities and associations of local public power systems oppose both the proposed abandonment of the statutory municipal/State preference in relation to the exemption process and the preference given to exemption applicants over non-owner license or permit applicants. The public power entities argue that States and municipalities that are not project owners are entitled to preferential treatment under the Act when competing with exemption applicants for the right to develop a site. They contend that in providing the Commission with the power to exempt certain projects from the Act, the Congress intended only to cut the red tape that accompanies licensing, not to establish a new system of priorities or preferences. These commenters assert that the preference is a controlling factor in dealing with any water power project within the Commission's jurisdiction, whether in an exemption context or not, and is not a licensing requirement from which a project may be exempted under section 408 of the ESA. They argue for the primacy of the licensing over the exemption process based on the safeguards they allege the former process to provide for the public interest. Licensing is to be supplemented by the exemption process, they say, only to the extent that licensing fails to encourage the development of a project. Based on this presumption, the American Public Power Association (APPA) proposes a procedure wherein any competition arising before the Commission between exemption applicants and license or permit applicants would convert the process to one for a permit or a license, with the municipal and State preferential rights under section 7(a).

The approach reflected in the proposed rule is supported by most of the private hydropower developers and investor-owned utilities. They claim that the statutory preference, as well as the threat of condemnation by a successful State or municipal licensee under section 21 of the Act, deters private developers from even identifying a site by applying for a permit or license. If the preference system were invoked under the proposed exemption rule, these commenters contend that it would also deter exemption applicants. The Congress did not prohibit the Commission from providing exemption from section 7(a) of the Act when it granted the Commission discretion to exempt projects "in whole or in part from the requirements (including the licensing requirements) of Part I" of the Act. One commenter cited changes in economic circumstances since the enactment of the preference as a basis for eliminating the preference, at least from the exemption process.

The Commission agrees that the legislative history of section 408 of the ESA does not address this issue; the statute is clear on its face, however. The Commission may choose to exempt any or all projects under 5 megawatts from the provisions of section 7(a) or any other requirement of Part I of the Act. Thus, the Commission may regard as equals all applicants that seek to develop a small hydroelectric power project, within the context of the exemption process, without regard to whether they are governmental entities or not. There are several important reasons for doing so. Moreover, when competitors are otherwise equal, there are good reasons for generally preferring the project owner.

The exemption authority was provided by the Congress to encourage small hydropower development. This will occur as a result of removing regulatory impediments where possible and by allowing market forces relatively free reign consistent with that purpose. In light of this objective, the Commission believes the national interest in encouraging development of a small renewable energy resource project with new or added capacity is more important than Federal Government control of who actually does it or who gains the immediate economic benefit.

APPA argues that, where competition for a site exists, an exemption is unnecessary; the exemption process is intended to encourage development of previously ignores sites, not necessarily or primarily to expedite development of known and usable sites. The Commission believes APPA's position misses several significant points. First, unless those persons with first-hand knowledge about available sites, frequently project owners, are encouraged to come forward with plans for development, the question of competition will never arise with respect to much currently unexploited hydropower potential. Few non-public project owners will venture to formulate development plans and apply for exemption, if they would thereby expose their projects to taking facilitated by the municipal/State preference. Moreover, even where hydropower sites are known to be available for further development, speed of development would likely be sacrificed by undertaking a comparison of the relative merits of the applications submitted by public and private developers and by the inevitable conversion, under the APPA proposal, to a licensing proceeding at any time that a public entity that is not the project owner filed a competing application. Many years or experience in administering the Act show that cases involving competing applications take significantly longer to decide and demand more time and money from the perspective of developers. Thus, encouraging States and municipalities to file competing applications increases the institutional barriers to rapid hydropower development.

Other considerations support the Commission's decision not to apply section 7(a) to the exemption process. The procedures in the proposed and final rules do not prevent a state or municipality from developing a site. A non-owner public entity will be in at least as good a position as any other non-owner; it may still negotiate with the project owner for access to the project, whether by sale, lease, or other available contractual device. In other words, a state or municipality may do business like anyone else in order to obtain an interest sufficient to develop the site.[6] If that fails, the alternative of a condemnation proceeding under the state laws governing eminent domain is often available. A state or municipality that obtains the necessary property rights by purchase or condemnation may then obtain an exemption as the project owner. Or, as APPA itself pointed out, the state or municipality may often be able to condemn an exempted project under state law after it has been exempted. In fact, APPA acknowledged that the primary benefit of retaining the preference under section 7(a) would be that the state or municipal licensee would suffer less adverse political reaction by condemning a project under Federal law, as a licensee, than under state law.

Project owners, public or private, should be able to go forward expeditiously to develop small projects. The operation of a statutory preference should not be allowed to encourage competing applications by non-owners and infuse uncertainty into the development of small hydroelectric power plants and thereby defeat Congressional objectives. The Commission can most effectively use its authority under section 408 of the ESA by dealing only with persons that have the requisite property interests to bring new capacity on line as soon as possible.

Some commenters oppose the preference given project owners under the proposed rule. The proposed rule provided, under § 4.103, that exemption applications filed by project owners would be preferred to permit or license applications, if filed within the public notice period prescribed for the permit application, with some exceptions. Opponents point out that the statute says nothing about project owners, that non-owner private or public developers will be reluctant to file for a permit or license in light of the preference for exemption applicants, that some project owners may seek just to block development, and that speculation in hydropower sites may result from a rule that puts a premium on project ownership.

First, the Commission anticipates that, because of the project owner preference, in a few instances persons who are not project owners may indeed be dissuaded from applying for licenses or permits for projects which are recognized as ripe for further development. In most instances, however, the absence of an automatic preference for public developers, the lower likelihood of competition, the prospect of an exemption from licensing, and the new economic attractiveness of hydropower will be strong incentives for a previously reluctant owner to apply to develop a project. The more attractive development is economically, the more likely it is that market forces will lead a project owner to develop a project or a non-owner to make an offer that will induce the current owner to sell sufficient rights to render the non-owner an owner. Moreover, the exemption authority in the ESA is founded upon the presumption that more capacity will be developed sooner by means of exemption than by license. Therefore, in the interest of expeditious development, it makes sense not only to favor exemption applications over those for permits or licenses, but also generally to favor that class of persons more immediately capable of capitalizing on exemptions by undertaking to add or rehabilitate generating capacity—those who already own sufficient property interests.

It is important to note that, although project owners are in a more "favored" position than normally under the Act—in that they are subject only to market pressures and not to artificially created regulatory pressures—the final rule does not isolate the owner entirely from regulatory pressures. The final rule clarifies that a project owner will not obtain an exemption where a non-owner who was also a preliminary permittee has made timely application for a license. In addition, however, it provides that where a non-owner license applicant has filed first, the Commission will favor that application unless the plans of the subsequent exemption applicant would better develop the water power potential of the project. The final rule also allows a non-owner to file for a license after the exemption application, if it proposes a plan of power development that would render the project significantly better than any exemptible project.

The hierarchy of application preferences in § 4.104 balances the public interest in expeditious development under an exemption with some opportunity for non-owners to compete and propose more comprehensive development of a site. A permit application reflects an intent by the applicant only to study a site for development. A license application manifests both the plans and the capability for imminent development. Because exemption applications for projects 5 megawatts and less will be similar in content and imminence of development to license applications, they will be preferred to permit applications, just as license applications are preferred to permit applications (*see* § 4.33). Similarly, because the exemption applicant must be a person with sufficient real property interests in any non-Federal lands involved to develop a site immediately, the rule provides such applicants with advantages over license applicants who have no such property interests. For example, a first-filed exemption application will bar any license application, with the one limited exception noted above. Favoring a project owner will also tend to reduce the costs of litigation associated with competition for a power site and the transaction costs of transferring the project involuntarily from the owner to some other developer.

One commenter advocated that no exemption application should be considered by the Commission if there is a previously filed license application. This approach was originally set forth in the draft rule. If a project owner failed to seek a permit or an exemption or license to develop a site, the price of that failure would be to risk loss of the site to a non-owner who first proposed development in a permit or license application. While this approach itself has not been adopted, the Commission recognizes that there is a problem. The Commission believes that the rule should not discourage interested non-owners who wish to exploit the full water power potential of a site in circumstances where the project owner does not take timely action to protect itself and develop the site adequately. Therefore, under § 4.104 the protection afforded the project owner has been restricted as follows: a project owner may not file for exemption for a project for which there is a preliminary permittee that files a timely application for license, *i.e.*, before the permit expires; even where there has been no permit, a non-owner license applicant will be preferred to an exemption applicant that files second and in competition with the license applicant, unless the plans of the exemption applicant would better develop the water power potential of the affected water resources; and a non-owner may file for a license in competition with an accepted exemption application, if the non-owner proposes significantly better power development that would make the project ineligible for exemption, *i.e.*, at least 7.5 megawatts, or 50% more capacity than the maximum allowed under the statute.

One commenter suggested that exemptions be limited to a term of 30 years. The final rule does not limit the term of exemptions; the Commission has chosen to grant exemptions in perpetuity, subject to standard conditions. A project with only a 30-year exemption would be virtually a licensed project by another name. The only considerations that would warrant reexamination of whether to continue the exemption for a project after a term of years are more appropriate for licensed projects or are, like the possibility of more comprehensive development, provided for under the scheme of exemption.

It was proposed that a project owner be given the latitude to apply for an exemption at any time up to final Commission action on a pending license or permit application or to convert a license application to an exemption application at any time before the license application is approved. The proposals have been rejected because they pose unreasonable burdens upon efficient administration of the permit, license, and exemption programs. To provide some certainty to the Commission, its staff, and other interested agencies and persons and to allow expeditious completion of proceedings, the nature of the proceeding and the participant must be fixed at a relatively early point. Therefore, the project owner is afforded only a limited time either to file in competition with a non-owner's application for a license or permit or to request that a license application be treated as one for exemption.

Numerous commenters opposed the exclusion of projects located on Federal lands from this case-by-case exemption process. The failure to include such projects was described as especially burdensome on project owners in the western United States, where a large portion of all land is Federally-owned and a high probability exists that a project will involve Federal land in some way, even if the dam and powerhouse, for example, are located on private property. Some commenters proposed deletion of the reference to Federal lands in the definition of "small hydroelectric power project," leaving project owners to negotiate access to Federal lands within one year. If rights to use public lands were not obtained, the procedure could then be changed to a licensing procedure. It was also suggested that the rule should exempt projects with only transmission lines on Federal lands or that any project on Federal lands leased for power purposes be made exemptible.

The Commission acknowledges the difficulty facing western developers with respect to this issue under the proposed rule. The Commission's concern is both to protect lands in the public domain and to permit development of projects that depend on such lands for power generation or distribution. In light of the comments, the Commission has lifted the proposed restriction relating to projects on Federal lands. The reference to Federal lands has been removed from the definition of "small hydroelectric power project." Projects that use Federal lands may therefore be exempted from any portion of Part I of the Act, subject to the new standard condition in Article 5 [§ 4.106(e)], which states that an exemption from licensing in no way confers any right to use or occupy Federal lands. Such rights must be obtained from the appropriate Federal land management agency. If the right to use any Federal lands involved is not obtained for the project within one year, the Commission may accept a license application for the project from any person to whom it is authorized to issue licenses under section 4(e) of the Act, and may revoke the exemption.

Although there was general approval for the Commission's decision not to use the broad definition of "project" in the Federal Power Act in establishing the scope of an exemptible facility, it was further suggested that, for purposes of exemption, a "project" be defined as an individual generation site, presumably the power-plant and appurtenant facilities. This would, of course, have the effect of preventing aggregation of the capacity of more than one powerhouse that uses water from the same impoundment for purposes of determining whether a project is within the 5 megawatt limitation. In those few cases where several small, independent power generating sites depend on a single impoundment, whether or not under license, a narrower definition would probably optimize the developmental impact of the exemption process. However, there are various practical difficulties in defining "project" solely in terms of a generation facility, without, among other things, encouraging applications that might attempt to circumvent the 5 megawatt statutory limitation; or failing to include the dam and impoundment in either an exempted project or a licensed project where the Commission could impose conditions on their use and maintenance—for environmental or dam safety reasons, for example. The Commission nevertheless recognizes the value, in some circumstances, of exempting certain sites that clearly are separate and distinct from other generating sites at the same dam and impoundment and has provided an opportunity for applicants to obtain waiver of the provisions that necessitate aggregation of all capacity at a single impoundment.

The definition of "small hydroelectric power project" includes run-of-river projects, a concern of two commenters. The 5 megawatt capacity limitation will not be applied only to capacity *added* to a project, as requested by another commenter. Such application of this statutory limitation would permit exemption of large projects based on a comparatively insignificant addition to capacity. That could be an unfortunate result from an environmental or safety perspective. It appears from the language of Title IV of PURPA, as amended by § 408 of the ESA, that Congress intended to give the Commission authority to exempt small hydroelectric projects, as a whole, not small increments of capacity at large hydroelectric projects. In response to a related comment, the installation or increase in capacity that is required for a project to qualify for exemption does include replacement or rehabilitation of old capacity as well as adding increments of new capacity, so long as the project owner is proposing to develop capacity that was not previously being used. Although this was explained in the preamble to the proposed rule, a new definition of "install or increase" clarifies this position.

The proposed rule excluded from exemption any project that is part of a licensed project with more than one development or impoundment. Insofar as the licensing and relicensing of projects is concerned, the exemption from licensing of small portions of these larger projects will frequently produce some confusing results, such as how to apply and coordinate license and exemption conditions, especially in light of the limitation on license term and the possibility of competition for a new license. The Commission believes that a licensee may often be able to amend its license to accommodate the addition of a small generation facility with about the same filing obligations and waiting time as provided under the exemption process.[7] Two changes in the rule have evolved from consideration of this issue, however. First, the Commission will not accept an application for exemption from licensing of only a part of any licensed project. The entire licensed project may be exempted, if it is eligible for exemption under the rule. This limitation may of course be waived under § 4.103(d), if consistent with the statute in a particular case. Secondly, if a person applies for exemption from provisions other than licensing, that application should occur in relation to a license application or application for amendment of license. The rule therefore treats such applications differently from applications for exemption from licensing. Procedurally, they will be handled within the context of the licensing process. In addition, the form and content of the application will be significantly different, and much simpler, under § 4.108.

Commenters addressed various issues relating to project ownership and the question of who may apply for exemption. The argument made by some commenters (discussed above) that license applicants should be preferred to, or given consideration equal to, exemption applicants is offered in conjunction with a request that project owners not be preferred to non-owners, based on the fact that an exemption is arguably a special type of license to develop a project. Based on this assumption (which is incorrect, given the differences between license and exemption procedures, conditions, privileges, and responsibilities), it is argued that persons other than project owners should be able to obtain exemptions and that not to permit this will lead to the speculative acquisition of power sites.

The Commission continues to believe that of granting exemptions to persons who lack the requisite property interest to develop the site is generally likely to lead to confusion over the right of owners and non-owner exemption applicants. Moreover, an exemption is of little use to a non-owner, especially if the project owner is already a licensee or license applicant that seeks to develop the project under a different series of conditions and responsibilities. Any speculative activity that arises as a result of the value which the final rule places on project ownership ought to be regarded as an expected result of free market activity. If speculation is not accompanied by actual development of a site, the exemption may be revoked by the Commission under Article 3 which, as amended from the proposed rule, would also prevent the site from being exemptible for the following two years, thereby diminishing the economic attractiveness of being the project owner and failing to develop the project.

In conjunction with the modification of the proposed rule to accommodate Federal lands, the definition of "project owner" has been eliminated. the same concept appears in § 4.103(b), however, for circumstances involving all non-Federal lands or a mix of Federal and non-Federal. Where a project involves only Federal lands, there is no "project owner" of non-Federal lands affected, and thus the final rule allows any person to file for exemption of that kind of project.

In a related matter, the rule has also been revised with respect to who may apply for a license after an exemption is granted. As proposed, if the real property interests in non-federal lands necessary for development were split among two or more persons, only the combination of owners could apply for a license for the project in the first instance. In instances like changes in a joint venture that obtained exemption (such as an acrimonious falling out of partners) or splitting of unitary property interests to disparate persons (such as, through death and distribution), the proposed rule might have created an undue barrier to expeditious development. Thus, the final rule allows any person with any necessary real property interest in the non-Federal lands involved to apply for a license after an exemption has been granted One commenter requested that a project owner who acquires a project after a license application is filed should be permitted to apply for exemption. If the new owner is not a former permittee and the public notice period has not expired, he may apply for exemption. If the former owner has already applied for exemption, that application may be amended to reflect the new owner as the applicant, just as permit or license applications are sometimes amended under § 1.11 of the Commission's regulations.

The question is raised about how conflicting claims of sufficient property rights would be resolved. The application for exemption from licensing requires evidence of ownership for that purpose. There is nothing unusual about the nature of such rights in the case of exemptions; they will range from fee title to rights-of-way to options to buy.[8] The proposed and final rules give examples of what constitutes project ownership. If there were no Federal licensing at all, the same ownership interests would have to be perfected to develop a site. Of course, a fee owner and a person with an option to buy would each qualify to file for exemption before the option is exercised. However, since the exemption attaches to the project and not the owner, any conflict that arose between the two would be left for private resolution, subject to the conditions of the exemption. But, a mistake about the sufficiency of an exemption applicant's property interests will not invalidate an exemption that has been granted. In addition, the problems that a project owner may face with respect to other kinds of regulatory approvals must be resolved outside the exemption process.

Article 2, in § 4.106(b), requires compliance with any conditions prescribed by fish and wildlife agencies. Commenters claim that this is a forfeiture of Commission responsibilities which will deter exemption applications. they request that the Commission prescribes lenient environmental conditions where appropriate or possible, eliminate Article 2 where state licensing procedures exist, or at least urge other agencies to make conditions minimal. Section 408 of the ESA, which incorporates part of section 30 of the Act, gives fish and wildlife agencies authority to establish binding exemption conditions for carrying out the purposes of the Fish and Wildlife Coordination Act. The Commission will not interpret the statute otherwise. However, it is for the Commission to insert the recommendations of those other agencies as conditions of an exemption. In order to provide a project owner with fair notice of the conditions imposed on the exempted project and to administer the exemption process efficiently, Article 2 requires compliance with fish and wildlife agency conditions that have been included with the applicant's Exhibit E or submitted directly by the agency within the time provided for comment.

One state agency posed several questions about environmental matters. A state need not intervene to participate in the environmental consultation process prescribed in Exhibit E. An applicant must supply evidence of the consultation which it must undertake with appropriate state and Federal agencies or the application will be considered patently deficient and rejected. In response to the request for a definition of critical habitat, the Commission notes that the U.S. Fish and Wildlife Service establishes and publishes a list of critical habitats in its regulations. Finally, the Commission will, as requested, provide a list of fish and wildlife agencies on request. Such a listing would be too cumbersome to include in the rule.

Two commenters argue that projects at "existing dams" include those at breached dams, no matter how badly breached a dam may be, and that the Commission should clarify this in the rule. Such projects should be made exemptible if the project owner proposes to reconstruct the dam, they say. The commenters point to section 408(a)(6) of PURPA which defines "existing dam" for purposes of small hydroelectric power projects as "any dam, construction of which was completed on or before April 20, 1977, and which does not require any construction or enlargement of impoundment structures (other than repairs or *reconstruction*) * * *." (Emphasis added.) One commenter states that the Department of Energy, in granting PURPA loans, considers this to have the effect of including among existing dams even badly breached dams. It is not clear that a dam so badly breached that nothing remains but abutments is an "existing dam." Section 408 (a)(1) of PURPA defines a small hydroelectric power project as one located "at the site of an existing dam", and this definition limits the scope of our authority to grant exemptions. The explanatory statement of the Conference Committee which accompanied the original Title IV of PURPA states that "the phrase 'at the site of an existing dam' should be strictly construed to mean at the site of an existing impoundment."[9] Badly breached dams will have no impoundment and an argument may be made that such dams do not qualify for the financial assistance program under Title IV. Whether Congress intended such dams to be excluded from exemption under the 1980 amendment to PURPA is unclear.

Several comments focused on the contents of the application under proposed § 4.106, now § 4.107. One commenter argued that exemption and license applications should be the same for small projects and another stated that the exemption application was too similar to a license application with respect to the information required. The Commission has held the amount of information required of exemption applicants to the minimum necessary to discharge its responsibilities under section 408 of the ESA and to determine a project's eligibility for exemption. The application is similar to, but has fewer filing requirements than, the short-form license application which may become applicable to any project of 5 megawatts or less at an existing dam. Of course, if a license is sought under Part I of the Federal Power Act, safety, comprehensive development, environmental, and engineering considerations generally necessitate a greater volume of data. Both in terms of the input and the end result, the exemption process is far simpler than the licensing process. The Director of the Division of Hydropower Licensing or any regional engineer will supply prospective applicants with an example of a completed exemption application, on request.

It is important to note that, unlike the proposed rule, the final rule provides two kinds of exemption applications in §§ 4.107 and 4.108. Exemptions from licensing will require submittal of data on a project's location, its structural and operational features, and its environmental impact. Exemption from provisions other than licensing require only identification of those provisions.

It was suggested that older dams be exempted from the requirements of Exhibit G to supply drawings of the project, because original drawings may no longer be available. The Commission will insist on such drawings, even if they have to be prepared anew, because they are essential to Commission evaluation of the projects's structural integrity.

If the developer varies its project design somewhat from that described in Exhibit A, the Commission will not revoke the exemption, as one commenter feared. Exhibit A is not submitted in order for the Commission to approve the design. As long as there is no new impoundment, capacity in excess of 5 megawatts, or radical change in construction that suggests a lack of good faith, the Commission will not be concerned, unless dam safety considerations make exemption from regulation otherwise unreasonable.

The Environmental Protection Agency (EPA) requests that Exhibit E contain analysis of flows downstream from any diversion structure and a request for state certification under section 401 of the Clean Air Act. Exhibit E now contains sufficient water resource data and analysis for interested agencies to evaluate the application. In addition, if no license is issued, there is no applicable section 401 requirement.

Some commenters claim that Article 3 did not allow an applicant sufficient time to begin construction, because of probable delays in power market negotiations, state approvals, consultation, and feasibility studies. The Commission has extended this time provision to 18 months to accommodate such potential difficulties. However, further extension would be contrary to the general purpose of the exemption process. The applicant must anticipate and solve these problems independently either before or during the time that it is seeking exemption, if necessary. In any case, revocation is not automatic under any term or condition of the rule. It should be pointed out that feasibility studies, delays from which concerned the Department of Energy, should not occur after the grant of an exemption, but are best performed before that time. An exemption application is, as noted earlier like a license application in terms of the stage of planning, investigation, and readiness to develop. The Commission will not require progress reports with respect to construction schedules because such enforcement mechanisms are more appropriate for licenses.

There are numerous miscellaneous comments to which a response would be useful.

1. EPA requests notice of any exemption application. EPA is already on a list of recipients for all permit, license, and exemption applications. EPA also requests an Exhibit E with such notice; the exhibit may be obtained from the applicant.

2. EPA argues that only projects operating in the run-of-river mode should be exempted; the Commission does not wish to prejudge the environmental impacts of projects that are not run-of-river. They will be considered on a case-by-case basis.

3. EPA advocates a standard term requiring that the instantaneous flow releases directly below the dam must equal or be greater than the seven consecutive day mean low flow within a 10 year recurrence. The Commission will entertain comments on appropriate flow released from EPA and other Federal and state agencies in individual cases under this case-by-case rule.

4. The 120-day automatic grant provision is too short to allow for proper safeguards from environmental problems, argues EPA; if an EA is required, EPA states that this time period should be suspended. The Commission expects that a satisfactory and complete environmental assessment of a project will occur within 120 days, in most cases. The statutory goal of expeditious development requires appropriately short deadlines. If necessary, the 120-day period may be suspended.

5. One commenter states that the Commission should exempt all projects 5 megawatts and less, leaving such projects to state regulation. The Commission is examining the extent to which a generic exemption should be granted, separately from this rule.

6. Although licenses for projects are transferrable from one licensee to another with Commission approval, no transfer provision is necessary for an exempted project. The exemption is for a project, not a person, and sale or other transfer of the project does not affect the exemption. No Commission approval of transfer is required. However, new project owners may wish to notify the Commission of the transfer of ownership for purposes of any later proceeding relevant to the exempted project; otherwise, any notices will only be published in the Federal Register and possibly a local paper and sent to the last known owner.

7. One commenter contended that no exemption application should be considered for one year after revocation of an existing exemption. This would arguably encourage development within the prescribed time by exposing the owner to a license application by a state or municipality, with preference. The Commission generally agrees, but adopts a two-year rule under standard Article 3.

8. One commenter would have the Commission dismiss an exemption application if water rights disputes arise. This would be an invitation for some parties to dispute water rights. As indicated above, any such disputes should be worked out at the state level.

9. Some commenters state the rule should address the issue of later, more comprehensive development plans and a procedure should be established to accommodate such proposals. The Commission will consider proposals to better develop the water resources of the region in a manner that may affect a previously exempted project. An exemption does not preclude later creation of another licensed project that contains, overlaps, or otherwise is mutually exclusive with an exempted project, subject to whatever compensation to property owners—including owners of the exempted project—may be necessary. The procedure to develop a waterway more comprehensively is licensing.

10. One comment indicated that an exemption can be used to circumvent the requirements and safeguards of licensing and that the Commission should ensure that an exemption applicant will significantly add to the project's capacity, recommending a 20 percent increase. The Congress intended to encourage "circumvention" of the licensing process, and imposed no

prerequisite like a 20 percent increase in capacity or a showing that improvements would be uneconomical without the exemption. The Commission believes such restrictions would unduly restrict the availability of exemptions.

11. A state agency requested that much more time be allowed for the consultation process and that the rule impose a consultation fee. Since additional hydropower works to everyone's benefit, all agencies should cooperate to speed its development. The final rule does not extend the proposed deadline. Nor is a fee appropriate for performing consultations on exemption applications when no fee is required for consultations on license applications. An agency that does not believe the value to the public it serves warrants consultation on a particular case may decline to consult and comment on that case.

12. One commenter questioned whether the exemption amounted to a waiver of commission jurisdiction; another commenter quite correctly pointed out that the conditions of an exemption demonstrate that the Commission has continuing responsibility for a project, to some extent. We agree.

III. Section-by-Section Summary of the Rule

The rule applies to applications for exemptions of small hydroelectric power projects having a proposed installed generating capacity of 5 megawatts or less from all or part of Part I of the Act. A small hydroelectric power project is defined as a project that uses the water power potential of an existing dam or a natural water feature without need for a dam or man-made impoundment.

§ *4.101 Purpose.*

This rule provides case-by-case exemption procedures.

§ *4.102 Definitions.*

The proposed rule defines the term "project" more narrowly than does section (3)(11) of the Act. Neither the ESA nor PURPA defines "project". Under the final rule, a project would include only those facilities directly associated with a single man-made impoundment or a natural lake. Under section (3)(11) of the Act, a "complete unit of development" might include more than one impoundment and a series of hydraulically coordinated dams. As stated above, a project, as defined by this rule, is not exemptible from licensing requirements if it comprises only a part of any licensed project, as the term "project" is used in section (3)(11) of the Act, unless the licensee obtains waiver of this restriction under § 4.103(d). Because the definition of "project" in this rule is more circumscribed and therefore may include fewer generating units, eligibility for exemption will be greater than if "project" were construed to include all dams, impoundments, and powerhouses in a large coordinated unit of development. The scope of the definition of "project" is sufficiently broad to exclude from exemption any in a series of separately developed generation facilities that have an aggregate capacity in excess of 5 megawatts and that use the same impoundment. However, the final rule contains a waiver provision (§ 4.103(d)) that would permit individual generation facilities to be exempted if waiver were granted.

If there is no lake or impoundment, "project" is defined in the rule to include the diversion structure and the facilities associated with it. However, a diversion structure that obstructs most of a natural body of water will be considered a dam, a distinction that bears on the physical scope of a project and the probable environmental impacts.

The statutory term "proposed installed capacity" is defined in the final rule to mean that an applicant must propose to add some new generating capacity at a project in order for the project to qualify for an exemption.

The definition of "install or increase," a phrase initially used in the definition of "small hydroelectric power project," states that this capacity includes proposals to install capacity where none existed previously, to replece or rehabilitate abandoned or unused existing capacity at a project, and to add capacity where there is existing operable capacity. The proposed installed capacity will be computed as the sum of both newly-developed capacity and existing capacity and may not exceed 5 megawatts in the aggregate.

This section also defines "dam," "existing dam," "Fish and wildlife agencies," "Federal lands," "non-Federal lands", "real property interests", "person," "qualified exemption applicant," and "qualified license applicant."

§ *4.103* *General provisions.*

Section 4.103 describes which projects the Commission may exempt from all or part of Part I of the Act. This section also places a limitation on exemption of portions of licensed projects. Without a waiver only an entire licensed project may be exempted, if otherwise eligible under other criteria. This section also contains a general waiver provision.

This section also states who may apply for exemptions. If only Federal lands would be used for development, anyone may apply for exemption from licensing. If any non-Federal lands would be necessary to develop and operate the project, only a person, or group of persons holding all of the real property interests necessary to develop and operate that project (such as ownership in fee, a leasehold, easement, right-of-way, or an option to obtain such interest) may apply for an exemption from licensing. This prevents a person who lacks the requisite non-Federal real property interests to develop the project from obtaining an exemption for another person's project.[7] The rule does not require that a person have such ownership interests in all of the land occupied by the entire project (*e.g.*, all of the lands for the impoundment) to be considered a qualified exemption applicant. A person need only possess interests in the project necessary to develop and operate hydroelectric power at the site.

§ *4.104* *Relationships among applications, exemptions, permits, and licenses.*

This section sets forth how exemptions from licensing and applications for exemption from licensing will be treated in relation to other kinds of applications relating to development of a project and any permits or licenses. Section 4.104 of the rule sets forth a system of priorities and preferences for persons who file to develop a site. Paragraph (a) establishes rules that apply when there is an outstanding license or permit for a project or when a permit or license application has been filed before the exemption application. Paragraph (c) prescribes what happens when a project is exempted or the project owner has applied for exemption before a license or permit application is submitted.

This section protects a person other than the project owner who has already applied for a permit or license, from being defeated by a project owner's untimely application for exemption from licensing. The Commission will accept an exemption application, or a notice of intent to submit one, that competes with a pending permit or license application only if it is submitted during the protest and intervention period prescribed in the public notice for the permit or license application. But the Commission will not accept an exemption application if a preliminary permittee has made timely application for license, even if the exemption application is submitted during the public notice period. Moreover, the Commission will not accept an application for exemption from licensing if a person other than the exemption applicant then has an unexpired preliminary permit or license.

This section also protects first-filing exemption applicants who own the non-Federal lands necessary for an exempt project from later permit or license applicants that would seek to take and develop the project. If an exemption application is pending, the Commission will not accept an application for a preliminary permit; nor will it accept a license application from a person other than the exemption applicant, unless the license application proposes total installed capacity of at least 7.5 MW. An exemption applicant may file a license application, but the exemption application will be deemed withdrawn and other interested persons may compete for the license. Similarly, any person owing non-Federal real property interests necessary to permit development of an exempted project may file a license application, but will then be exposed to competition by other interested developers, including municipalities with a preference under Section 7(a) of the Act.

A license applicant that is a qualified exemption applicant may request that its application for license be first considered as an application for exemption, if its license application was the first filed for the project. Such a request may be filed at any time during the period for filing protests and petitions for intervention prescribed in the public notice for its license application. A preliminary permit applicant that is a qualified exemption applicant may submit an exemption application during the public notice period for its permit application, if its permit application was the first filed for the project.

Paragraph (e) of § 4.104 contains noteworthy provisions about Commission treatment of applications that propose to develop the same project. An exemption application submitted in competition with an application for a preliminary permit will be preferred to the permit application. However, as between license applicants and exemption applicants, the Commission will favor the first-filed application unless the plans of the subsequent applicant would better develop the water power potential at the project.

Municipalities or other public entities that are not project owners and that apply for preliminary permits or licenses that compete with exemption applications will be governed by the same rules as other applicants for permits or licenses, and will not receive the preferential treatment provided under section 7(a) of the Act.

§ *4.105 Action on exemption applications.*

Section 4.105 of the final rule contains the procedures and timing provisions for Commission action on an exemption application. If the application is for exemption from provisions other than licensing, the Commission will act in the context and according to the procedures for the related application for license or amendment of license. The procedures for exemption from licensing are provided in this section.

Once an application for exemption from licensing is submitted, the Commission will allow only 45 days for correcting deficiencies. The Commission may on its own motion, or on the motion of any party in interest, order a hearing on an application for exemption. Interested agencies will have 60 days to comment on an application. If an agency does not comment within the 60 days, that agency will be presumed to have no objection to the exemption requested. A non-responding fish or wildlife agency will be presumed to have no conditions to impose other than those specified in Exhibit E of the application. If the Commission does not act within 120 days of the notice that an application is accepted, it is automatically granted on certain standard conditions.

§ *4.106 Standard terms and conditions for exemption from licensing.*

The rule specifies, in § 4.106, five standard conditions of every exemption. The installation of new capacity at the exempted project must begin within 18 months and completed within four years of the date of issuance of the exemption. Failure to begin or complete development of the project on a timely basis may lead to acceptance of license applications for the project and revocation of the exemption. These provisions are designed to prevent tying up the project site for an unreasonable time without development. Other standard conditions relate to the Commission's enforcement powers, compliance with conditions imposed by fish and wildlife agencies during the exemption process, and the navigation servitude of the United States to which all exempted projects on navigable waters remain subject. A fifth article is added to require the acquisition of rights to use any Federal lands involved from the administering Federal land management agencies within one year. If they are not obtained timely, the Commission may accept license applications for the project and revoke the exemption.

The Commission may provide further (non-standard) conditions in each exemption from licensing, based on the circumstances of the exemptible project, under § 4.105(b)(6). Among other things, Commission will be concerned about the safety of project works. For example, if a project contains a dam that is ten or more meters in height above streambed, impounds 2.5 million or more cubic feet of water, or is determined to have a high hazard potential, the Commission may require periodic inspection of the project by an independent consultant.[8]

§ *4.107 Contents of application for exemption from licensing.*

The rule describes the required format and contents of the application for exemption from licensing in § 4.107. The application includes an introductory statement, which identifies the applicant and the project, as well as Exhibits A, B, E, and G. Exhibit A must include a description of the facility and the proposed mode of operation. Exhibit B is a general location map.

Exhibit E is an environmental report submitted to facilitate compliance with the National Environmental Policy Act of 1969. It also contains information to facilitate compliance with the National Historic Preservation Act, the Endangered Species Act, and the Fish and Wildlife Coordination Act.

Exhibit G is a set of drawings showing structures and equipment. These drawings will permit the Commission to review the project structures, existing and proposed, in order to understand their environmental and dam safety implications.

§ *4.108 Contents of application for exemption from provisions other than licensing.*

Any applicant for exemption from selected parts of the Act other than the licensing requirements must submit a list of sections from which it seeks exemption, appended to an application for license or amendment of license.

Other amendments

The Commission also amends its regulations to delegate to the Director of the Office of Electric Power Regulation, or his designee, the limited authority to grant applications for exemptions from all or part of Part I of the Act, provided an environmental impact statement is not required, for small hydroelectric power projects or small conduit hydroelectric power projects.

IV. Effective Date

The Commission finds good cause to make this rule immediately effective.[9] The procedures established by this final rule provide the means for exemption of certain hydroelectric power projects from various statutorily imposed requirements. The rule therefore both "recognizes an exemption" and, at least potentially, "relieves a restriction." Given the determination of the Congress to encourage expeditious development of hydroelectric projects and the large numbers of preliminary permit and license applications being submitted to the Commission, an immediate effective date is in the public interest.

(Energy Security Act of 1980, Pub. L. 96–294, 94 Stat. 611; Federal Power Act, as amended, 16 U.S.C. §§ 792–828c; Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §§ 2601–2645; and the Department of Energy Organization Act, 42 U.S.C. §§ 7101–7352; E.O. 12009, 3 CFR 142 (1978))

In consideration of the foregoing, the Commission amends Parts 4 and 375 of Chapter I, Title 18, Code of Federal

Regulations, as set forth below, effective November 7, 1980.

By the Commission.

Kenneth F. Plumb,

Secretary.

—Footnotes—

[1] Pub. Law 96-294, 94 Stat. 611. Section 408 of the ESA amends, *inter alia,* sections 405 and 408 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. §§ 2705 and 2708).

[2] 45 Fed. Reg. 58368, September 3, 1980.

[3] 45 Fed. Reg. 49591, July 25, 1980.

[4] The Commission's staff is currently developing further rulemakings to implement the provision in section 408(b) of the ESA allowing the Commission to exempt "classes or categories" of projects, thereby obviating any application procedure.

[5] *See,* Order No. 76, 45 Fed. Reg. 28085, April 19, 1980.

[6] The Commission also notes that this rule gives a state or municipality that is a project owner protections and preference against other interested states or municipalities that are non-owners, who might otherwise get a license for the project and condemn it under the Federal power of eminent domain.

[7] The Commission will consider a rulemaking designed to extend most of the advantages of short-form license applications to all water power projec.s at existing dams with a total capacity of 5 megawatts or less. This would also be the form used to amend an existing license to include a facility of this size. The Commission has in the past completely processed such license amendments in as little as 3 months.

[8] Possession of state power of eminent domain is not an adequate substitute for ownership of non-Federal lands. The possibilities of bitter and lengthy condemnation litigation before development could go ahead and the 18-month limit on commencing construction portend too great a risk that exemptions in such circumstances would be wasted proceedings. An entity with state power of eminent domain may, of course, take the necessary interests and then apply for exemption.

[9] H. R. Rep. No. 95–1750, 95th Cong., 2d Sess. 106 (1978).

[7] Under Part I of the Federal Power Act and Part 4 of the Commission's regulations, a person need not have sufficient property interest to develop power at a site in order to obtain a preliminary permit or a license. However, property interests must always be perfected to develop a project.

[8] These criteria are in Subpart D of the Commission's proposed Regulations Governing the Safety of Water Power Projects and Project Works, issued June 16, 1980, 45 *Fed. Reg.* 41608, June 19, 1980 (Docket No. RM80–31).

[9] Under the Federal Power Act (FPA), Commission action may take effect prior to the disposition of petitions for rehearing. (*See* § 313(c)) The Commission is of the view that the rehearing provisions contained in § 313 of the FPA apply to this rule due to the relationship of the exemption provision of PURPA to the licensing provisions of Part I of the FPA. Persons participating in this rulemaking should be aware that under § 313 of the FPA an application for rehearing is a jurisdictional prerequisite to obtaining judicial review.

[¶ 30,205]

45 F. R. 76664 (November 20, 1980)

[Note: The January 1, 1981, effective date of the amendments has been stayed pending the issuance of an order granting or denying rehearing of Order No. 108, 46 F. R. 2975, January 13, 1981.]

18 CFR Part 271

[Docket No. RM80–21; Order No. 108]

Sales of Natural Gas Made Under the Natural Gas Policy Act of 1978 (Sections 110, 105 and 106(b)) That are Sales of Intrastate Gas

November 14, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: By this rule, the Commission amends its regulations to provide that, for sales of natural gas made under the Natural Gas Policy Act of 1978 that are sales of intrastate gas, the maximum lawful prices provided for under sections 105 and 106(b) of the Act are presumed to compensate sellers for all State severance taxes that were in effect by operation of State law as of November 9, 1978. The regulations are also amended to permit an add-on for increases of State severance taxes brought about by changes made in State law after November 9, 1978. Finally, the regulations have been amended as to the definitions of the terms "contrect price" and "price under the terms of the existing contract." These changes are being made after comment on the Proposed Rule noticed January 16, 1980 (45 FR 5747 (Jan. 24, 1980)) under this docket.

EFFECTIVE DATE: The regulations are to apply for deliveries made on or after January 1, 1981.

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I. Introduction and Background.

On January 18, 1980, the Commission issued a Notice of Proposed Rulemaking in this docket (45 FR 5747, January 24, 1980) in which it gave notice of a proposal to amend the interim regulations under section 110 of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3320) regarding the treatment of State severance taxes with respect to natural gas subject to section 105(b)(1) of the NGPA (15 U.S.C. 3315). This order amends § 271.1102 to provide that, except in the case of State severance taxes increased by State law enacted after November 9, 1978, sellers under existing and successor intrastate contracts subject to section 105 of the NGPA and intrastate rollover contracts subject to section 106(b) of the NGPA may not collect State severance taxes in addition to the maximum lawful price. These final rules also clarify the definitions of "contract price" and "price under the terms of the existing contract" at § 271.504 of the Commission's regulations.

Section 105 establishes ceiling prices for first sales under "existing intrastate contracts," and is implemented in Subpart E of Part 271 of the commission's regulations (18 CFR 271.501, *et seq.*).[1] Section 271.502(a) of the regulations, which implements section 105(b)(1) of the NGPA, provides that if the "contract price" that was paid on November 9, 1978, (or that would have been paid had deliveries occurred) was equal to or less than $2.06 per MMBtu, then the maximum lawful price is the lower of the section 102 maximum lawful or the "price under the terms of the existing contract" as those terms were in effect on November 9, 1978. Section 271.501(b) of the regulations, which implements section 105(b)(2) of the NGPA, provides that if the contract price that was paid or that would have been paid on November 9, 1978, exceeded $2.06 per MMBtu, the ceiling price is the higher of the contract price on that date escalated by an inflation factor or the section 102 ceiling price. Section 271.504 states that the terms "contract price" and "price under the terms of the existing contract" mean all proceeds paid by the purchaser inclusive of State severance taxes.

Section 110(a)(1) of the NGPA, which is implemented in Subpart K of Part 271 (18 CFR 271.1102), generally provides that the price for a first sale of natural gas shall not be considered to exceed the maximum lawful price applicable to the first sales of such natural gas if the first sale price exceeds the maximum lawful price to the extent necessary to recover State severance taxes attributable to the production of such natural gas and borne by the seller.

In Order No. 68 the Commission examined the question of whether State severance taxes should not be included in the section 105 "contract price" in view of the statement of the Joint Conference Report that "all ceiling prices under this Act are exclusive of State severance taxes borne by the seller." [2] It determined that they should not and stated that the further question "as to whether the seller may add the amount of any such taxes borne by him to the section 105 ceiling price under section 110 of the NGPA and under § 271.1102 of the Commission's regulations" would be addressed in this docket.

In the Notice of Proposed Rulemaking issued in this docket, the Commission tentatively took the view that in most cases it should not extend the provisions of § 271.1102 to section 105(b)(1) because of an essential difference that it perceived between the nature of the section 105(b)(1) ceiling price and other maximum lawful prices in Title I of the NGPA. The Commission noted that, unlike other ceiling rates that are tied to a specific price established by Congress, each ceiling price under section 105(b)(1) is established by referring to the negotiated price contained in the intrastate contract that existed on November 9, 1978. Noting that, "[s]everance taxes are among many costs of providing service that a producer will take into consideration when he negotiates price terms," the Commission then states:

> However, in all cases, we believe it is reasonable to presume that when the seller negotiated the contract, he took into consideration the amount of severance tax for which he was to be liable. The total proceeds to be received under the contract, therefore, are presumably sufficient to repay the seller for all severance taxes he may be obligated to pay. Because the section 105(b)(1) price is based on this consideration, it is our tentative view that no additional allowance under section 110 is necessary to allow the seller to "recover" severance taxes paid by him because the seller is already recovering all such taxes in the proceeds he receives.[3]

The Commission also expressed the tentative view that, to the extent a seller is constrained by section 105(b)(1) from collecting the full "price specified under the terms of his contract," the seller should be allowed to collect State severance taxes under the authority of section 110 in addition to the section 105(b)(1) ceiling price. However, with respect to first sales subject to section 105(b)(1)(A), the Commission proposed the following amendments to § 271.1102:

> (c) Under § 271.502(a) of Subpart E, the price under the terms of the contract (as those terms were in effect on November 8, 1978) is deemed to be sufficient to recover State severance taxes (whether borne by the seller or reimbursed by the buyer). State severance taxes may not be recovered under this section except to the extent the price under the terms were in effect on November 8, 1978, exceeds the maximum lawful price specified for new natural gas (Subpart B of Part 271) in Table I of § 271.101(a).

These amendments were proposed to prevent sellers from collecting any amount representing a recovery of State severance taxes which could be presumed to be recovered in the total proceeds received under the terms of the existing intrastate contract.

The Commission also explained that it viewed (again tentatively) section 105(b)(2) differently from 105(b)(1). Although both sections relate to sales under existing intrastate contracts, the Commission believed that the pricing mechanism of section 105(b)(2) more closely resembles that of other sections of the NGPA. The Commission therefore did not propose any restriction in § 271.1102 respecting the right of the seller to collect State severance taxes in addition to the section 105(b)(2) ceiling price.

The Commission requested specific comments on the proposed rule and any issues arising out of its proposal including whether the prohibition against the collection of State severance taxes should be expanded to include all gas subject to sections 105(b)(1), 105(b)(2), and 106(b)[4] of the NGPA. The Commission also requested comments respecting special treatment for increases in State severance taxes after November 9, 1978, and the general relationship between sections 105, 106(b), and 110.

Written comments were due on or before February 19, 1980. Twenty-four comments were filed.[5] In addition, the Commission held a public hearing on these issues on April 10, 1980 at its offices in Washington, D.C. Eleven persons appeared and presented their views at the hearing.[6]

The final rule provides that the maximum lawful prices prescribed in Subparts E and F are presumed to recover all State severance taxes borne by the seller and levied on the sale by State law enacted on or before November 9, 1978. State severance taxes increased after November 9, 1978, may be collected over and above the applicable maximum lawful price to the extent such reimbursement is necessary. In addition, the definitions of "contract price" and "price under the terms of the contract" have been clarified.

II Summary of Comments.

While the position taken in each comment generally could be categorized according to whether the commenter was a purchaser or a seller, none of the comments supported the Commission's proposed rule or the suggested rationale underlying the rule. Generally, sellers focused on and criticized the

Commission's refusal to permit section 110 State severance tax allowances over and above the section 105(b)(1) maximum lawful prices.[7] Purchasers, on the other hand, focused on and criticized the extent to which the proposal would have required payment of State severance taxes even when the contract did not so provide.

A. *The application of section 110 State severance tax allowances with respect to existing, successor and rollover intrastate contracts.*

Generally, the sellers challenged the Commission's authority to preclude a seller from collecting State severance taxes over and above *any* ceiling price, including ceiling prices under section 105(b)(1). They interpreted section 110 to permit reimbursement of State severance taxes over the maximum lawful price, if contractually authorized, with respect to all categories of gas under the NGPA, including section 105 gas. In their view, nothing in the legislative history of the NGPA reveals a Congressional intent to carve out a special exception in the case of sales under section 105. In support of that view, they cited the words of the Joint Conference Report that: "*All* ceiling prices under this Act are exclusive of state severance taxes borne by the seller."[8]

Sellers also argued that equity demands that all intrastate sellers should be treated in the same fashion as interstate sellers and be allowed to collect State severance taxes in addition to the ceiling price. One commenter added that Congress recognized that tax payments detract from funds otherwise available to gas producers for the exploration and development of new reserves. Further, the commenter argued, Congress sought to ensure their recovery in all cases, including section 105 sales, by the addition of section 110(a)(1) allowances.

The qualification in section 110 that the costs must be "borne by the seller" was construed by some sellers as indicating that any time State severance taxes are levied on a sale, the seller has the authority to obtain reimbursement for such taxes over and above the applicable maximum lawful price. In addition, some sellers posited the theory that section 110(a)(1) operates to automatically increase the maximum lawful price itself by the amount of State severance taxes legally incident to the sale.

In summary, sellers held the view that section 110 permits sellers to obtain reimbursement for State severance taxes in any case in which such a tax is imposed over and above any maximum lawful price provided under section 105(b)(1), or any other maximum lawful price. Some insisted that once the maximum lawful price is determined, reimbursement for any State severance tax imposed on the sale is permitted by the NGPA and the contract may be amended to provide for such reimbursement.

Purchasers also contested the Commission's interpretation of section 110; however, their comments on this issue were more divergent than the sellers. One asserted that there is clearly a distinction between section 105 and other sections of the NGPA that does not justify the application of the section 110 allowances to sections 105 and 106(b) gas. (However, this commenter stated during the public hearing that it had not focused on whether section 110 would permit amendment of contracts to collect State severance taxes, but, instead, on whether the proposed regulations permitted sellers to demand reimbursement for State severance taxes absent specific tax reimbursement authority under the terms of the existing contract.[9]) Another purchaser argued that section 110 applies to all categories of gas including section 105(b)(1) gas, and, therefore any contract may be amended to permit the collection of any State severance tax imposed on the sale. That commenter emphasized, however, that the Commission should not permit the collection of State severance taxes absent specific contractual authority respecting tax reimbursement.

All comments from purchasers concurred with the Commission's observation that, unlike other sections of the NGPA, section 105(b)(1) ceiling prices are based on negotiated prices. However, contrary to the Commission's proposal, they suggested that such difference applies in the case of sections 105(b)(2) and 106(b) as well as section 105(b)(1). Accordingly, they would extend any restrictions applicable to section 105(b)(1) sales relating to collection of State severance taxes to all sales subject to sections 105 and 106(b). Purchasers, therefore did not challenge the Commission's finding that section 110(a)(1) has special application with respect to section 105, but were concerned that the rules applicable to sections 105(b)(1), 105(b)(2) and 106(b) were inconsistent and that the Commission should not permit reimbursement for State severance taxes absent clear contractual authority.

Finally, a seller and a purchaser asserted that the proposed rule unreasonably discriminates against intrastate sellers who were selling at low prices prior to the NGPA. They did not believe there is a valid reason for treating such sellers more harshly than those who were selling at higher prices.

B. *Presumption of recovery of State severance taxes.*

Nearly all of the commenters took issue with the Commission's presumption that the section 105(b)(1)(A) ceiling price already provides for the recovery of all State severance taxes borne by the seller. Sellers asserted that these contract prices were negotiated in an entirely different environment than that created by the passage of the NGPA, in that the parties were free to amend their contracts to respond to changed circumstances. Accordingly, they argued, these contracts were not drafted in such a way as to provide for all possible contingencies. It was assumed that amendments to the contracts could be made if and when circumstances changed. Furthermore, they argued that many of these contracts were negotiated in depressed markets in times of oversupply. Sellers argued that it cannot be presumed that the seller had sufficient bargaining power to obtain a price sufficient to provide reimbursement for all expenses that might arise in the future.

One commenter stated that the Commission's presumption respecting the sufficiency of the contract price to recover taxes is tantamount to writing tax reimbursement provisions into these contracts to which the parties had never agreed. It argued that Congress never intended such a result. It added that, in its view, the Commission's proposal conflicts with the two Congressional goals of section 105: to preserve the sanctity of intrastate contracts, and to eliminate the distinctions between the inter- and intrastate markets.

Purchasers, except in one comment, also suggested that the Commission's presumption was in error. In some situations the proposal would have required a purchaser to pay for State severance taxes in contravention of the terms of the contract or the understandings reached by the parties to the contract. Purchasers criticized the Commission for not focusing on the tax reimbursement terms of the existing intrastate contracts and relying on a presumption concerning the sufficiency of the proceeds to recover taxes. In the opinion of most of these commenters, the question of whether and to what extent tax reimbursements are already included in the proceeds received under section 105 should be resolved by looking to the express terms of the contracts. In particular, purchasers contested the Commission's proposed regulation implementing section 105(b)(1), according to which a seller constrained from collecting his full price under the terms of the existing contract, would be allowed to add-on taxes to the extent so constrained. They argued that the Commission incorrectly applied cost-based reasoning in assuming that the last bit of proceeds received are taxes, and, therefore, should be collected over and above the maximum lawful price. Purchasers also criticized the Commission's failure to restrict tax reimbursement under Section 105(b)(2). They felt that, in cases in which tax reimbursement is not *specifically* authorized by the contract, allowing a tax add-on would cause the terms of the contract to be superseded. Therefore they interpreted the proposal as contravening section 101(b)(9) of the NGPA.[10]

C. *Application of section 110 in the context of specific contractual clauses.*

All commenters asserted that the Commission misperceived how section 110(a)(1) should be applied in the context of specific contractual situations.

The Commission has taken the view that when reimbursements are appropriate the collection of section 110 allowances may be permitted over and above the various ceiling prices under Title I of the NGPA. Some sellers took a different view. They asserted that section 110(a)(1) operates to automatically increase each ceiling price by the full amount of the State severance tax obligation rather than permitting reimbursements over the applicable maximum lawful price. Accordingly, they claimed that the existence of a State severance tax liability automatically increases the ceiling by an amount "equivalent" to the amount of State severance taxes imposed on each respective sale. They concluded two things: First, the Commission is without authority to prohibit collection of State severance tax in any case because each *ceiling price* is increased by the amount of State severance taxes imposed on the sale; and second contractual clauses providing for collection of the highest maximum lawful price and redetermination clauses constitute sufficient contractual authority for the seller to obtain reimbursement for any State severance tax imposed on the sale.

It is with respect to this latter point that the purchasers particularly differed with the sellers. The purchasers generally argued, contrary to both the seller's and the Commission's proposals, that section 101(b)(9) of the NGPA would not permit collection of reimbursement for taxes absent specific contractual authority. They do not view section 110 as effectively adjusting the maximum lawful price. They view section 110 as permitting, in certain situations, payments over and above the maximum lawful price. Accordingly, a "price" increase provision (such as a redetermination clause) would not be sufficient by itself to authorize the collection of a tax allowance. Purchasers believe that the contract must specifically permit collection of State severance taxes before the seller should be permitted to collect them.

In the case of section 105(b)(2), purchasers interpreted the Commission's proposal to ignore and even contradict the express terms of many contracts. For example, they interpreted the proposed regulation as allowing a full tax add-on to the section 105(b)(2) ceiling price even where, pursuant to an express tax reimbursement provision, the terms of the contract on November 9, 1978, specifically provided that the buyer would not be responsible for state severance taxes. Purchasers believe that such disparate treatment of section 105(b)(2) sales indicated that the Commission failed to apply the same presumption of tax recovery that was applied with respect to section 105(b)(1) gas. They contested the Commission's rationale for different treatment and asserted that all section 105 sales are alike insofar as they are all based on prices negotiated by the parties.

D. *Double and triple recovery of taxes.*

One of the key issues in the comments dealt with the issue of double recovery of taxes. One of the purchasers explained how the Commission's proposal permits a double and even triple recovery of taxes in some cases. For example, if a section 105(b)(2) contract price on November 9, 1978, included 10 cents of tax reimbursement, that 10 cents is a part of the "total proceeds" and, thus, is included in the section 105(b)(2)(A) base ceiling price. The terms of the contract, therefore, provide for the first recovery of tax. The proposal would not prohibit the parties from amending the contract under the authority of § 271.1102, to provide that the seller may collect another 10-cent tax allowance in addition to the section 105 ceiling price. If they amend the contract they have provided a second recovery of the tax. In the event the contract rolls over and becomes subject to section 106(b), the 20 cents of tax reimbursement would be included in the section 106(b)(1)(A)(i) base ceiling rate, and again nothing in the proposal indicates that collection of another 10-cent tax allowance would be prohibited. In all 30 cents would be collected with respect to a 10-cent tax liability.

However, comments from some of the sellers suggested that there should be no question raised as to whether there is a double (or triple) recovery of taxes. In their view, the Commission is without authority to scrutinize the composition of ceiling prices to ascertain if taxes are already being recovered. They argued that Congress mandated in section 110 that an amount equivalent to taxes imposed on the gas could be collected in addition to each ceiling price under Title I without restriction. They also argued that the Commission cannot therefore restrict the amount of taxes collected as an addition to the ceiling price.

E. *Definitions of "contract price" and "price under the terms of the contract."*

Section 271.504 of the Commission's regulations defines "contract price" and "price under the terms of the existing contract" as follows:

> (a) *Contract price.* "Contract price," when used with respect to any specific date and contract, means:
>
> (1) The price paid per MMBtu under a contract for deliveries of natural gas occurring on that date; including any State severance taxes which are levied on gas subject to the contract (whether such taxes are borne by the seller or reimbursed by the purchaser).
>
> (2) If no deliveries of natural gas occurred under such contract on that date, the price per MMBtu that would have been paid had such deliveries occurred on that date, including any State severance taxes which would have been levied on gas subject to the contract (whether such taxes would have been borne by the seller or reimbursed by the purchaser).
>
> (b) *Price under the terms of the existing contract.* "Price under the terms of the existing contract" when used with respect to any specific date and contract means the price under the terms of the existing contract, as such contract was in effect on November 9, 1978; including any State severance taxes which are levied on the sale of natural gas subject to the contract (whether such taxes are borne by the seller or reimbursed by the purchaser).

Several commenters argued that the Commission should not have defined the term "price under the terms of the existing contract" to include State severance taxes as part of the total proceeds paid for the gas.[11] In Order No. 68 the Commission determined that it would not define that term in a manner that would require the subtraction of such taxes from the proceeds received in order to establish section 105 ceiling prices. These commenters relied on the already cited statement in the Joint Conference Report that "[a]ll ceiling prices under this act are exclusive of State severance taxes borne by the seller.[12]

The Commission also received numerous inquiries concerning the definition of these terms in § 271.504. Commenters suggested that, taken literally, these sections may require an amount representing tax reimbursement to be added to the proceeds paid out on date of enactment in all cases, even those in which the contract did not provide for tax reimbursement. Others have expressed confusion as to whether these definitions embody the Commission's "total proceeds" concept or whether they embody the view that the section 105 ceiling prices are deemed sufficient to recover all State severance taxes levied on the sale.

F. *Increased State severance taxes.*

There was little disagreement regarding how the Commission should treat increases in State severance taxes. Generally, the comments agreed that the Commission should permit collection of any increase in State severance taxes so long as the contract authorizes or is amended to authorize such collection. Some commenters did request that the Commission explain how it would treat amendments to contract reimbursement provisions for any increased State severance taxes. Others, mainly purchasers, also reiterated their view that specific "tax" reimbursement contractural authority must be present to collect such increased taxes.

Some questions were raised regarding how the Commission would treat increased State severance taxes when the contract contains increased tax provisions.

G. *Miscellaneous.*

1. *Effective date.* The proposal suggested that the final rule would have an effective date of April 1, 1980. One commenter suggested that the proposed rule would operate as a clarification or interpretation of the NGPA. Such a clarification, the commenter submits, should become effective retroactively as of the date the NGPA became effective.

2. *Price increases under the terms of the contract.* One commenter noted that the preamble to the proposal contained the statement that in the case of a section 105(b)(1) sale "the parties may not increase the price under the terms of the contract," and requested clarification.[13]

III. Discussion.

The Commission has carefully considered all comments received in this docket. It has also carefully reconsidered each of the views it tentatively advanced in the Notice of Proposed Rulemaking issued January 18, 1980, in this docket as well as the decision it made in Order No. 68 to decline to subtract taxes from the total proceeds paid to establish section 105 ceiling prices. For the reasons expressed below, the Commission now believes that, except for increased taxes, its presumption regarding section 105(b)(1) sales should be applied to all first sales subject to section 105 or 106(b).

A. *The Commission's authority under section 110.*

A threshold question raised in the comments concerns the Commission's authority to determine that, in some cases, section 110 does not permit the collection of State severance taxes in addition to the maximum lawful price. The Commission affirms its view that it does have that authority.

Section 110(a)(1) permits the seller to collect State severance taxes in addition to ceiling prices only "to the extent necessary (for the seller) to recover" such taxes. Congress must be presumed to have a purpose for including that qualifying language. Otherwise it could have simply provided that an amount equal to such taxes could be recovered in all cases. Thus, to the extent that taxes are included in a ceiling price, it is not "necessary" to recover such taxes again through an allowance under section 110.[14] Consequently, the Commission believes that this view is not only permitted, it is mandated to prevent double collection of such taxes.

Furthermore, the Commission is not persuaded that section 110 has already operated to automatically increase each individual ceiling rate by an amount "equivalent" to taxes. Section 110(a)(1) is plainly a State severance tax allowance section. It permits tax add-ons, but only once and only to the extent not already included in the applicable ceiling rate.

B. *The presumption of tax reimbursement respecting section 105.*

1. *The Basis of the Presumption.* In its Notice, the Commission expressed the view that, because of the negotiated origin of the section 105(b)(1) ceiling price, it could be presumed that the seller bargained for and obtained a price sufficient to recover State severance taxes the seller is obligated to pay. Accordingly, the Commission found that it was appropriate to generally deem the section 105(b)(1) ceiling price to be "sufficient" to recover all State severance taxes imposed on the sale and precluded a tax add-on in any such case under the authority of section 110.

The Commission affirms this view. However, because of the number of comments that contested the foregoing presumption, the Commission wishes to clarify and expand its rationale.

Unlike other ceiling price sections of the NGPA, the initial starting point of all section 105 ceiling prices is a contract price arrived at by negotiation of the parties. Prior to enactment of the NGPA, the intrastate seller would have had the opportunity to bargain for a rate that would, at a minimum, recoup his day-to-day operating expenses. Usually, a businessman would be in a position to use that opportunity to ensure that, for any sale made by him, all investment and operating expenses would be recouped. To assume for purposes of formulating the regulations that the seller would have accepted a rate *lower* than that required to recoup at least operating expenses, regardless of the specific terms of the contract, conflicts with our notions of how the business world operates.[15] Taxes are one such expense. Therefore, as a matter of practical business acumen, we must presume that total proceeds recoup operating expenses, including taxes, estimated by the seller to exist at the time the contract was executed.

To the extent such out-of-pocket expenses (indeed, any costs) increased after the contract was executed, commenters tell us that the seller always anticipated that he would have the opportunity to bargain for a rate increase to recover such increased outlays. This adds support to the presumption that, as a practical business matter, the seller would have done so rather than operate at a loss. The intrastate seller had the opportunity up to the date of enactment of the NGPA to bargain for, and receive, a rate that would recoup all out of pocket expenses, including State severance taxes. Accordingly, as of November 9, 1978 (the key date for purposes of determining the starting point of all section 105 ceiling rates), the total proceeds paid by the buyer can be presumed to include full reimbursement for taxes levied as of that point in time.

By utilizing the "contract price" as well as the "price under the terms of the existing contract" as of November 9, 1978 to establish section 105 ceiling prices, Congress created a mechanism by which taxes could be included in the section 105 ceiling rates. That mechanism was grounded on recognizing that the parties generated the initial ceiling rates through the process of negotiation. That mechanism for including tax reimbursement in a ceiling rate is not present in other sections such as sections 102 or 103. In those sections, Congress declined to provide a means to channel tax reimbursement into the ceiling rates. It was Congress that established those initial rate levels devoid of tax reimbursement and it was Congress that decided to allow tax reimbursement only under section 110.

2. *The scope of the presumption.* Having concluded that the initial starting point of all section 105 ceiling prices (the contract price on date of enactment) contains full tax reimbursement as of that date, it follows that such tax recovery becomes a permanent and continuing component of the section 105 ceiling rate. That level of tax recovery is frozen into the ceiling rate and can be deemed to be collected as long as the seller is permitted to collect at least that same level of total proceeds.

In all cases under section 105, the tax content of the ceiling rate is established on November 9, 1978 by reason of the negotiated origin of the ceiling rate—the freely negotiated contract price as of the day before that date. All section 105 ceiling rates commence at the level chosen by the parties, regardless of how high or low the starting rate happened to be. Section 105 only operates to temper further additions to that initial base price. It does not eliminate any remuneration already included in that base starting-point rate level. Like bricks added to an established foundation, the further rate increases permitted by the various alternative section 105 ceiling rate mechanisms only add to that which is included in the base rate established by the parties as of November 9, 1978. Section 105 accordingly permits the *continued* collection of such amount of State severance tax reimbursement as was included in that original base starting rate on November 9, 1978.

The fact that the full "price under the terms of the existing contract" may be subsequently constrained to the section 102 price level by reason of section 105(b)(1)(B) is not dispositive. The imposition of the alternative section 102 rate only acts to restrict *further* price increases. It cannot take away anything, including tax reimbursement, that was originally included in the base starting rate.

The question is *not* whether the seller is permitted to continue to collect the full price under the terms of the existing contract. Rather, the question is simply whether the seller is permitted to collect at least the same level of total proceeds per MMBtu as he collected on the day before enactment of the NGPA. As long as he continues to collect at least that level of proceeds, it can be presumed that he has recovered the same level of tax liability levied on that date.[16]

The same principle applies to section 105(b)(2). That section, like 105(b)(1), only restrains further increases in the ceiling price, which ceiling price commences at the "contract price" chosen by the parties and which necessarily recovers all existing taxes.

Section 106(b) also falls within the purview of the Commission's assumption. Section 106(b) does not "roll-back" prices to below what they were under the existing intrastate contract in the month of the rollover. That section, like section 105, only adds to the last ceiling rate collected under the expired contract; which rate necessarily included full reimbursement of all taxes imposed by State law in effect as of November 9, 1978.

However, the Commission recognizes that it is not enough to deem all section 105 or 106(b) ceiling rates to be merely "sufficient" to recoup State severance taxes as the Commission did in the case of section 105(b)(1) in its proposed amendment to § 271.1102. Given the level of NGPA rates, all ceiling rates under the NGPA are "sufficient" to recover such taxes. Sufficiency implies only the possibility that they may be actually recovered. Based on the foregoing analysis, the Commission wishes to clarify that, in its opinion, all section 105 and 106(b) ceiling rates are more than just "sufficient" to recover State severance taxes imposed by State law enacted as of November 9, 1978; they actually can be presumed to include a full recovery of such taxes. Accordingly, the Commission has revised proposed § 271.1102(c) to expand its scope to incorporate all section 105 and 106(b) sales and to clarify that such ceiling rates are presumed to include full tax reimbursement for all taxes imposed by State law enacted as of November 9, 1978.

C. *Definitions of "contract price" and "price under the terms of the contract".*

For the reasons discussed above, the Commission continues to rely on the total proceeds concept in defining both "contract price" and "price under the terms of the contract." The "price" under a section 105 contract, whether it is a section 105(b)(1) or (b)(2) contract, only has meaning when set in the context of all reimbursements provided by the purchaser. Therefore the Commission does not accept the distinction in the meaning of the term "price" asserted by commenters, as between "contract price" and "price under the terms of the contract."

In response to confusion regarding whether the definitions embody the total proceeds concept or whether they embody the view that section 105 ceiling prices are deemed sufficient to recover all State severance taxes levied on the sale, the Commission has clarified the definitions. The purpose of those definitions was that the "total proceeds" of the sale are to be used in establishing these prices even if the proceeds include amounts earmarked as "tax reimbursement." Therefore, the definitions have been changed to expressly include the total price paid for delivery of the gas, including any amounts paid which were received as reimbursement for State severance taxes paid by the seller.

D. *Increased taxes.*

The Commission recognizes that the level of tax reimbursement presumed to be contained in the section 105 and

106(b) ceiling rates is dependent on the particular tax rate that was effective as of November 9, 1978. However, in the event of an increase in the tax rate after that date, it cannot be presumed that such increased tax obligation will be recovered. As the commenters have noted, the NGPA altered the context of these sales and now, in many cases, prevents the free renegotiation or amendment of the price of these contracts. Accordingly, the Commission's amendment to § 271.1102(c) will provide that the applicable section 105 or 106(b) ceiling price will not be deemed exceeded if the ceiling price is exceeded by an amount necessary to recover the amount of increase in State severance taxes effected by State law enacted after November 9, 1978.[17]

Reference to the provisions of the contract after November 9, 1978, to establish the extent of recovery of "increased" taxes is not inconsistent with the policy of disregarding the terms of the contract to establish what "existing" taxes were being recovered as of November 9, 1978, and earlier. As discussed above, the November 9, 1978, contract price was the product of negotiations in an unregulated market and tax reimbursement can be presumed. Following enactment of the NGPA no such presumption can be made with respect to additional tax burdens newly imposed by a state.

Since the terms of the contract must be resorted to on and after December 1, 1978 to establish the ceiling rate, it follows that contract provisions may be referred to in order to establish the extent of increased tax reimbursement. Thus, to the extent the seller receives remuneration for increased taxes by the receipt of the section 105 or section 106(b) ceiling rate, then such increased taxes may not be recovered under § 271.1102. It is not "necessary" to recover such taxes again. However, to the extent that those ceiling rates do not include remuneration for the increased taxes, nothing should prevent the parties from amending the contract to provide for full reimbursement of an increased tax obligation created by State law enacted after November 9, 1978.

F. *Contractual authorization.*

The Commission has considered the comments of those who argued that, pursuant to section 101(b)(9) of the NGPA, a specific tax reimbursement provision of a contract is required in order to collect a section 110 tax allowance. The Commission disagrees. Section 101(b)(9) only clarifies that ceiling prices do not supersede the rate level provided by a contract. What an intrastate contract provides, however, is in the first instance, up to the parties. In the event of a dispute as to the interpretation of such contracts, the dispute should be resolved in the state courts. Therefore, the rule (respecting new post-December 1, 1978, state severance taxes) is not written to require payments when no such payments are authorized by contract.

Thus, the rule permitting a section 110 add-on for increases in state severance tax rates enacted after November 9, 1978 does not override section 101(b)(9) which preserves existing contractual rights. The parties must agree to the collection of the increased taxes. If, in the view of the parties, the contract does not provide that authorization, then the contract must be amended to provide that authority prior to collection of the section 110 add-on. Nothing in this rule prevents such a consensual amendment.

Consequently, while section 101(b)(9) requires contractual authorization, the Commission shall leave the question of contractual authority to collect increased State severance taxes to the parties.

G. *Miscellaneous.*

1. Effective date. In the absence of Commission guidance prior to issuance of this rule, parties to contracts may have interpreted the regulations as authorizing collections of State severance taxes in circumstances in which this rule prohibits such collection. The Commission does not believe that it would be equitable to insist upon refunds when the seller relied on such interpretation and the contract permitted such collections. Therefore, the Commission will not require a seller to refund State severance taxes collected with respect to deliveries of gas which occurred prior to January 1, 1981, solely by virtue of the fact that the collections violate the regulations issued in this rule. The Commission notes, however, that this conclusion does not effect contractual rights parties may have under the contract. If State severance taxes were collected in violation of the terms of the contract a purchaser may rely on the terms of the contract and insist upon contractual rights under state law.

2. *"Price under the terms of the contract"*. The statement in the preamble to the proposal that under section 105(b)(1) "the parties may not increase the price under the contract as those terms were in effect on November 9, 1978," was not intended to indicate that the price may not increase pursuant to the terms of the contract as they existed on November 9, 1978. Parties may not change the terms of the contract to affect a price increase not permitted by the terms that were in effect on November 9, 1978. Fixed and indefinite price escalator provisions which were in the contract on November 9, 1978, may operate to increase the price pursuant to such terms subject to the section 102 limitation of section 105(b)(1)(B) of the NGPA.

3. *Adjustments.* Nothing in the rules issued herein prevents any party from filing for an adjustment to the provisions of § 271.1102(c)(i) on the grounds that, by its application, it creates special hardship, inequity, or an unfair distribution of burdens. This may, for example, occur in the situation of a seller who is subject to the constraints of section 105(b)(1) (which contains a section 102 cap), and who cannot collect reimbursement for state severance taxes even though the sales contract so provides because such reimbursement would result in a price above the NGPA ceiling. Or it may occur in the situation of a seller who shows that the presumption of tax recovery contained in the rule does not or should not otherwise apply to his sales. In either case, or in other situations, relief from the provisions of § 271.1102(c)(i) may be required to the extent necessary to permit a seller to recoup state severance taxes borne by him.

IV. Summary of Amendments.

In § 271.504 the definitions of "contract price" and "price under the terms of the existing contract" have been clarified. They include the total price paid per MMBtu for delivery of the gas. The total price includes any amounts which were received as reimbursement from the purchaser for State severance taxes paid by the seller.

Section 271.1102 is amended to provide that the ceilings in Subparts E and F are presumed to recover all State severance taxes, except for any State severance tax increased by State law enacted after November 9, 1978.

(Natural Gas Policy Act of 1978 (15 U.S.C. 3301 *et seq*))

In consideration of the foregoing, §§ 271.504 and 271.1102 of Part 271, Subpart E, Chapter I of Title 18, Code of Federal Regulations, are amended; and issued as final rules, as set forth below to be effective for natural gas delivered on or after January 1, 1981.

By the Commission.

Kenneth F. Plumb,

Secretary.

—Footnotes—

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[1] Order No. 68, "Final Regulations Under Sections 105 and 106(b) of the Natural Gas Policy Act of 1978," Docket No. RM80-14 (issued Jan. 18, 1980) 45 FR 5678 (Jan. 24, 1980).

[2] S. Rep. No. 95-1126, 95th Cong., 2d Sess. at 90 (Aug. 18, 1978).

[3] Notice of Proposed Rulemaking, "Proposed Regulations Under Section 110 of the Natural Gas Policy Act of 1978," Docket No. RM80-21 (Jan. 18, 1980) at 4-5, 45 FR 5747, 5748 (Jan. 24, 1980) (footnote omitted).

[4] Section 106(b) deals with first sales under "intrastate rollover contracts." The maximum lawful price under that section is the higher of the maximum price paid under the expired contract in the month in which the rollover occurs as escalated by an inflation factor or $1.00 per MMBtu escalated

by an inflation factor from April 20, 1977. Section 106(b) is implemented in Subpart F of Part 271 (18 CFR 271.601, *et seq.*).

[5] The following companies filed comments on or before the due date:

Corpus Christi Oil and Gas Company; Undersigned Producers, *et al.* (Shell Oil Co., *et al.*); Joint Undersigned Companies, *et al.* (Tenneco Oil Co., *et al.*); Champlin Petroleum Company; Northwest Arkansas Producers Group; Transcontinental Gas Pipe Line Corporation; United Texas Transmission Company; Valero Transmission Company; Houston Oil and Minerals Corporation; High Plains Gas Consumers Association; Mesa Petroleum Company; Sun Gas Company; Conecuh-Monroe Counties Gas District, Alabama; Corbin J. Robertson; D. Tongue and Associates, Inc.; Terra Resources, Inc.; Delhi Gas Pipeline Corporation; Southland Royalty Company; Undersigned Producers; and Lone Star Gas Company.

The following companies filed comments after the due date:

The State of Texas; Texas Independent Producers and Royalty Owners Association; The City Public Service Board of San Antonio; and Texaco, Inc.

The Commission considered the late-filed comments in addition to all other comments in view of the fact that the public hearing was not commenced until April 10, 1980.

[6] Texas Independent Producers and Royalty Owners Association; Corpus Christi Oil and Gas Association; Northwest Arkansas Producers Group; Delhi Gas Pipeline Corporation; Lone Star Gas Company; Shell Oil Company; Conecuh-Monroe Counties Gas District of Alabama; Sun Gas Company; Tenneco Oil Company, *et al.*; United Texas Transmission Company; and the Independent Petroleum Association of America. Notice of the hearing was issued February 21, 1980, and required notice of intent to participate to be filed by April 4, 1980. A notice of the list of participants in the hearing was issued April 9, 1980.

[7] Section 110(a)(1) provides:

Sec. 110. Treatment of State Severance Taxes and Certain Production-Related Costs.

(a) *Allowance for State Severance Taxes and Certain Production-Related Costs.* Except as provided in subsection (b), a price for the first sale of natural gas shall not be considered to exceed the maximum lawful price applicable to the first sale of such natural gas under this subtitle if such first sale price exceeds the maximum lawful price to the extent necessary to recover.

(1) State severance taxes attributable to the production of such natural gas and borne by the seller, but only to the extent the amount of such taxes does not exceed the limitation of subsection (b).

The exceptions of subsection (b), relating to certain types of State severance taxes enacted after December 1, 1977, do not concern this rulemaking.

[8] S. Rep. No. 95–1126, 95th Cong., 2d Sess. at 90 (Aug. 18, 1979) (emphasis supplied).

[9] *See* Transcript of Hearing, "Public Hearing of Proposed Regulations under Sections 110, 105 and 106(b) of the Natural Gas Policy Act of 1978," Docket No. RM80–21, held at Washington, D.C. at 106 (Apr. 10, 1980).

[10] Section 101(b)(9) provides:

(9) *Effect on Contract Price.* In the case of—

(A) Any price which is established under any contract for the first sale of natural gas and which does not exceed the applicable maximum lawful price under this title, or

(B) Any price which is established under any contract for the first sale of natural gas which is exempted under subtitle B of this title from the application of a maximum lawful price under this title, such maximum lawful price, or such exemption from such a maximum lawful price, shall not supersede or nullify the effectiveness of the price established under such contract.

[11] In a petition to rehear Order No. 68 (45 FR 5678, January 24, 1980) Undersigned Producers (Shell Oil Company, *et al.*) asserted this point. The order responding to the petitions for rehearing of Order No. 68, reserved resolution of State severance tax issues, including the one raised here, for consideration in this final rule. Objections to issues resolved in this rule may be raised in petitions to rehear this order.

[12] *See* text accompanying note 8 *supra*. However, they did agree that the total proceeds should be employed in the case of determining the "contract price" on November 9, 1978, because that term is defined in section 105(c) to be the price "paid" or that would have been paid. They note that "the price under the terms of the existing contract" is not so defined.

[13] Notice, note 3 *supra* at 11, 45 FR at 5749.

[14] For an example of the inclusion of taxes in a ceiling price, and the Commission's recognition of this, see § 271.1102(b) respecting the disallowance of taxes already included in the Permian Basin Area Rates.

[15] *See, e.g.*, Transcript of Hearing, note 9 *supra* at 132. The Commission also does not believe that the bargaining power of intrastate producers was so weak prior to enactment of the NGPA that they could not get the buyer to pay a rate at least equal to their out-of-pocket expenses.

[16] For example, assume that the contract price on November 8 and 9, 1978, was $1.00 per MMBtu. It is deemed to incorporate 7¢ tax recovery. That ceiling rate ($1.00) is collected until January of 1980 when the seller negotiates a rate increase pursuant to a term of the existing contract, which rate increase is constrained to the section 102 level ($2.358). If a $1.00 ceiling rate can be deemed to recover 7¢ tax liability, then a $2.358 ceiling rate can likewise be deemed to continue to recover that 7¢ liability. In other words, everytime the seller collected the $1.00 in total proceeds, he is deemed to have recovered 7¢ in taxes. Permitting him to collect *more* than $1.00 (in the example—$2.358) cannot remove the presumption that the ceiling rate continues to include 7¢ tax recovery.

[17] There may be specific contract provisions in a section 105 (b)(1)(A) contract that require a purchaser to reimburse the seller for all or a portion of increased taxes. Several commenters, for example, pointed out that their contracts provide that the buyer shall reimburse the seller for 85 percent of increased taxes. In such cases, an additional collection under § 271.1102 of the full

increase in tax would not be "necessary" and therefore would not be allowed. In the example just cited, only the 15 percent of the increase not already recovered by the increase in the section 105 (b)(1)(A) ceiling rate would be recoverable and then only if the contract so provided.

[¶ 30,206]

45 F. R. 75671 (November 20, 1980); 46 F. R. 11812 (February 11, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Wyoming-1); Order No. 109]

Ceiling Prices

Issued: November 14, 1980.

AGENCY: The Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high cost gas subject to an incentive price (18 CFR 271.703). The rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Wyoming Oil and Gas Conservation Commission that the Frontier Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: November 14, 1980.

FOR FURTHER INFORMATION CONTACT:

Leslie Lawner, Federal Energy Regulatory Commission, Room 4308B, 825 North Capitol Street, NE, Washington, D.C. 20426, (202) 357-8299.

Victor Zabel, Federal Energy Regulatory Commission, Room 6100C, 825 North Capitol Street, NE, Washington, D.C. 20426, (202) 357-8559.

SUPPLEMENTARY INFORMATION:

I. Background

On August 5, 1980, the Wyoming Oil and Gas Conservation Commission (Wyoming) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations, that the Frontier Formation in Wyoming be designated as a tight formation in the Commission's regulations. On September 23, 1980, a Notice of Proposed Rulemaking was issued by the Director of the Office of Pipeline and Producer Regulation (OPPR) in Docket RM79-76 (Wyoming-1) (45 FR 66813, October 8, 1980), to determine if Wyoming's recommendation that the Frontier Formation be designated as a tight formation should be adopted. The Director of OPPR issued the notice pursuant to the authority delegated to him by Order No. 97, Docket No. RM80-68, issued on August 1, 1980 (45 FR 53456, August 12, 1980).

Interested persons were given until October 23, 1980, to submit written comments and information concerning Wyoming's recommendation. No party requested a hearing in this matter, and no hearing was held.

II. Discussion

The Commission, on February 20, 1980, issued an Interim Rule in Docket No. RM79-76 establishing procedures for designating tight formations and for qualifying gas wells completed in those formations for the section 107 high-cost gas incentive price. The recommendation filed by Wyoming was submitted under the Interim Rule. The procedures and requirements delineated in the Interim Rule were not significantly changed in the Final Rule issued by the Commission in this docket on August 15, 1980 (Order No. 99). In this rule, the Commission delegated the initial responsibility for identifying potentially qualifying tight formations to each jurisdictional agency. The rule requires jurisdictional agencies to establish procedures and conduct their own investigations to identify tight formations within their jurisdictions that meet the guidelines established by the Commission. The jurisdictional agencies will then submit written recommendations to the Commission that particular formations or portions thereof be designated as tight formations.

On May 14, 1980, Wyoming held a public hearing, in Wyoming Docket No. 65–80, for the purpose of accepting data in support of a nomination designating the Frontier Formation as a tight formation. After study of the data submitted at the hearing, and collection of additional data, Wyoming, on August 5, 1980, filed in Docket No. RM79–76, the first of its tight formation recommendations. Wyoming recommends that the Frontier Formation be designated as a tight formation. Wyoming references this recommendation as a Cause No. 1, Order No. 1. The United States Geological Survey concurs with Wyoming's recommendation.

A. Summary of Wyoming's Recommendation. The Frontier Formation is located in the Moxa Arch area in portions of Sweetwater, Uinta and Lincoln Counties, Wyoming. It extends from Township 15 North through Township 24 North and roughly from Range 110 West to Range 115 West. The vertical limits of the formation are defined by the Hilliard Shale, above, and the Mowry Shale, also known locally as the Aspen Shale, below. It consists of interbedded sands, shales and thin coals and is approximately 500 feet in thickness. The depth to the top of the Frontier Formation ranges from about 11,100 feet to 11,140 feet.

Wyoming's geologic description of the formation is presented as expert testimony received at the May 14, 1980 hearing. It includes discussions of the stratigraphy, structure, lithology and the environment of deposition. Also included is an exhibit containing a series of three photographs taken with a scanning election microscope at various magnifications. It illustrates the pore pattern of the reservoir rock of the Frontier in the Moxa Arch area. Additionally, two exhibits were received containing a listing of 218 wells with brief production histories. They assess the current status of activity in the area.

Wyoming states in its recommendation that the surface casing requirements and cementing requirements of surface casing of wells drilled in the proposed area are in accordance with Wyoming Oil and Conservation Commission General Rule 320. There is no ground water report prepared by the State of Wyoming to indicate any fresh water aquifers in the recommended area. However, Rule 320 assures that the development of this formation will not adversely affect the quality of any undetected fresh water aquifer. The Commission has reviewed Wyoming's submission and has concluded that designation of the recommended formation is not a major Federal action significantly affecting the quality of the human environment because significant impact to potable or potentially potable underground water by development of the Frontier Formation will not occur.

B. Comments. Three parties submitted comments in response to the Notice of Proposed Rulemaking. All commenters supported the recommendation that the Frontier Formation be designated as a tight formation.

C. Guidelines for Designation. In § 271.703(c)(2)(i) of its regulations, the Commission has established guidelines which a formation must meet to be designated as a tight formation. These are:

> (1) The average *in situ* gas permeability throughout the pay section is expected to be 0.1 millidarcy or less;
>
> (2) The stabilized production rate, against atmospheric pressure, of wells completed for production in the formation, without stimulation, is not expected to exceed production rates delineated in the table in § 271.703(c)(2)(i)(B) of the regulations,
>
> (3) No well drilled into the recommended formation is expected to produce, without

stimulation, more than five barrels of crude oil per day.

In addition, the final regulations require that any formation or portion thereof which has been authorized to be developed by infill drilling prior to the date of recommendation be excluded from the recommendation, if the jurisdictional agency has information which in its judgment indicates that such formation or portion thereof can be developed absent the incentive price for tight formation gas.

A summary of the data submitted by Wyoming confirming that wells completed in the Frontier Formation are expected to meet these guidelines is given below.

The permeability and flow rate data is derived from pressure transient tests performed on 37 wells. Eighty-six percent of the wells are operated by Amoco Production Company (Amoco). Marathon Oil Company (Marathon) is the operator for the remaining 14 percent.

A summary of average permeabilities, average flow rates for gas and oil and average depths is given below:

Data source	Number of data wells	Average			
		Permeability (millidarcy)	Depth (feet)	Gas rate (1,000 ft^3/d)	Oil rate (barrels per day)
Amoco Production Co.	32	0.0308	11,263	23[illegible]	0
Marathon Oil Co.	5	.0370	11,387	164	0
Weighted average		.0317	11,280	225	

[1] Prestimulation values.

1. *Permeability.* Testimony received by Wyoming at its public hearing attributes the low permeabilities encountered in the Frontier Formation to the very fine grain nature of the sands. This type of granular structure, coupled with clay diagenesis and cementation, serve to effectively block the pore throats constricting the flow of gas from the reservoir. Pressure transient test data provided by Amoco for 32 wells determined an average *in situ* gas permeability of 0.037 md. It is evident from the above results and the supporting evidence that wells drilled into the Frontier Formation are expected to show an average *in situ* gas permeability of less than 0.1 md.

2. *Stabilized Production Rates.* Stabilized production rates were calculated from absolute open flow calculations using a ratio of flow equations. The average pre-stimulation flow rate for wells in the Frontier Formation is 225 Mcf/day at an average depth of 11,280 feet. This rate is below the maximum rate of 927 Mcf per/day permitted by § 271.703(c)(2)(i)(B) of the regulations.

3. *Oil Production.* Wyoming briefly describes a laboratory phase determination study in which gas and liquid samples from two Frontier producing wells were collected. The laboratory test data confirmed that the hydrocarbon liquids in the combined well stream existed as a single phase at reservoir conditions. Thus, there is very little chance that a well completed in the Frontier Formation will produce in excess of 5 barrels of oil per day prior to stimulation.

4. *Infill Drilling.* No portion of the Frontier Formation was authorized to be developed by infill drilling prior to the date the recommendation was made by Wyoming.

III. Conclusion

The Commission has reviewed Wyoming's recommendation and the comments received in support thereof, and finds that the recommendation complies with the requirements of § 271.703(c)(3) of the regulations, concerning the contents of the recommendation. The Commission concurs with Wyoming's assertion, based on the consideration of the record which Wyoming submitted, that the Frontier Formation meets all the requirements for designation as a tight formation set forth in § 271.703(c)(2)(i), and should be designated as a tight formation.

IV. Effective Date

The Commission hereby makes the amendment to its regulations effective upon the date of issuance of this order. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. Therefore, good cause exists to waive the thirty day notice period preceding the effective date of the rule.

(Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.;* Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301–3432; Administrative Procedure Act, 5 U.S.C. § 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, Code of Federal Regulations, is amended as set forth below, and the amendment is issued as a final regulation effective November 14, 1980.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,207]

45 F. R. 76673 (November 20, 1980)

18 CFR Part 271

[Docket No. RM79-76 (Wyoming-2); Order No. 110]

Ceiling Prices

Issued: Novembr 14, 1980.

AGENCY: The Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high cost gas subject to an incentive price (18 CFR 271.703). The rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Wyoming Oil and Gas Conservation Commission that the Mesaverde Formation be designated as a tight formation.

EFFECTIVE DATE: November 14, 1980.

FOR FURTHER INFORMATION CONTACT:

Leslie Lawner, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357–8299.

Victor Zabel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Wasington, D.C. 20426 (202) 357–8559.

SUPPLEMENTARY INFORMATION:

I. Background

On August 7, 1980, the Wyoming Oil and Gas Conservation Commission (Wyoming) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations, that the Mesaverde Formation in Wyoming be designated as a tight formation in the Commission's regulations. On September 23, 1980, a Notice of Proposed Rulemaking was issued by the Director of the Office of Pipeline and Producer Regulation (OPPR) in Docket No. RM79–76 (Wyoming-2) (45 FR 66813, October 8, 1980), to determine if Wyoming's recommendation that the Mesaverde Formation be designated as a tight formation should be adopted. The Director of OPPR issued the notice pursuant to the authority delegated to him by Order No. 97, Docket No. RM80–

68, issued on August 1, 1980 (45 FR 53456, August 12, 1980).

Interested persons were given until October 23, 1980 to submit written comments and information concerning Wyoming's recommendation. No party requested a public hearing and no hearing was held.

II. Discussion

The Commission, on February 20, 1980, issued an Interim Rule in Docket No. RM79-76, establishing procedures for designating tight formations and for qualifying gas wells completed in those formations for the section 107 high-cost gas incentive price. The recommendation filed by Wyoming was submitted under the Interim Rule. The procedures and requirements delineated in the Interim Rule were not significantly changed in the Final Rule issued in this docket by the Commission on August 15, 1980 (Order No. 99). In this rule, the Commission delegated the initial responsibility for identifying potentially qualifying tight formations to each jurisdictional agency. The rule requires jurisdictional agencies to establish procedures and conduct their own investigations to identify tight formations within their jurisdictions that meet the guidelines established by the Commission. The jurisdictional agencies will then submit written recommendations to the Commission that particular formations or portions thereof be designated as tight formations.

On June 4, 1980, Wyoming held a public hearing, in Wyoming Docket No. 92-80, for the purpose of accepting data in support of a nomination designating the Mesaverde Formation as a tight formation. After study of the data submitted at the hearing, and collection of additional data, Wyoming, by Cause No. 1, Order No. 2, filed a recommendation on August 7, 1980, in Docket No. RM79-76 that the Mesaverde Formation be designated as a tight formation. The United States Geological Survey concurs with Wyoming's recommendation.

A. Summary of Wyoming's Recommendation. The Mesaverde Formation is located in the Wamsutter Area in portions of Sweetwater and Carbon Counties, Wyoming. It extends from Township 13 North through Township 28 North and roughly from Range 90 West to Range 110 West. It is bounded by the Rock Springs Uplift to the west, the Continental Fault to the north, the Rawlins Uplift to the east, and the Cherokee Ridge to the south. The vertical limits of the formation are defined by the Lewis Shale, above, and the Steele Shale, below. The formation varies from horizontal to approximately 35 degrees on the west flank of the Rawlins Uplift. The producing sandstones in the Mesaverde Formation, which consists of interbedded sands, shales, and coals, possess porosities of 8 to 15 percent, and water saturations of 40 to 60 percent as derived from log analysis. The formation ranges from 2000 to 2500 feet in thickness and the average depth to the top of the Mesaverde Formation is approximately 10,125 feet.

Wyoming's geologic description of the formation is presented as expert testimony received at the June 4, 1980 hearing. It includes discussions on the stratigraphy, structure, lithology and the environment of deposition. Also included is an exhibit containing four photographs taken with a scanning electron microscope at various magnifications. It illustrates the pore pattern of the reservoir rock of the Mesaverde Formation in the Wamsutter area. Additionally, two exhibits were received containing a listing of 528 wells with brief production histories. They assess the current status of activity in the area.

Wyoming states in its recommendation that the surface casing requirements and cementing requirements of surface casing of wells drilled in the proposed area are in accordance with Wyoming Oil and Gas Conservation Commission General Rule 320. There is no ground water report prepared by the State of Wyoming to indicate that there are fresh water aquifers in the recommended area.

However, Rule 320 assures that the development of this formation will not affect the quality of any undetected fresh water aquifer. The Commission has reviewed Wyoming's submission and has concluded that the designation of the recommended formation is not a major Federal action significantly affecting the quality of the human environment because significant impact to potable or potentially potable underground water by development of the Mesaverde Formation will not occur.

B. Comments. Three parties submitted comments in response to the Notice of Proposed Rulemaking. The commenters supported the recommendation that the Mesaverde Formation be designated as a tight formation.

C. Guidelines for Designation. In § 271.703(c)(2)(i) of its regulations, the Commission has established guidelines which a formation must meet to be designated as a tight formation. These are:

(1) The average *in situ* gas permeability throughout the pay section is expected to be 0.1 millidarcy or less;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production in the formation, without stimulation, is not expected to exceed production rates delineated in the table in § 271.703(c)(2)(i)(B) of the regulations; and

(3) No well drilled into the recommended formation is expected to produce, without stimulation, more than five barrels of crude oil per day.

In addition, the final regulations require that any formation or portion thereof which has been authorized to be developed by infill drilling prior to the date of recommendation be excluded from the recommendation, if the jurisdictional agency has information which in its judgment indicates that such formation or portion thereof can be developed absent the incentive price for tight formation gas.

A summary of the data submitted by Wyoming, confirming that wells completed in the Mesaverde Formation are expected to meet these guidelines is given below.

A summary of average permeabilities, average flow rates for gas and oil and average depths is given in the chart set out below:

Data source	Number of data wells	Average			
		Permeability (millidarcy)	Depth (feet)	Gas rate (1,000 ft^3/d)	Oil rate (barrels per day)
Amoco Production Co	38	0.0410	10,170	214	
Marathon Oil Co	3	.0180	9,524	190	
Weighted average		.0393	10,125	212	

[1] Prestimulation values.

1. *Permeability.* Testimony received by Wyoming at its public hearing (Wyoming Docket No. 92–80) attributes the low permeabilities encountered in the Mesaverde Formation to the fine to medium grained nature of the sands as well as the presence of authigenic minerals. These minerals, mainly clays, quartz and some carbonates, crystalize, then grow and ultimately form bridges across the pore throats between the grains, reducing the formation permeability significantly. They also fill the pore cavities, effectively reducing the formation porosity. Pressure transient test data provided by Amoco for 38 wells demonstrate an average *in situ* gas permeability of 0.0410 md. Marathon's data from its three wells yielded an average *in situ* gas permeability of 0.018 md. It is evident from the above results and the supporting evidence that wells drilled into the Mesaverde Formation are

expected to show average *in situ* gas permeabilities of less than 0.1 md.

2. *Stabilized Production Rate.* Stabilized production rates were calculated from absolute open flow calculations using a ratio of flow equations. Average prestimulation flow rate for the Mesaverde Formation is 212 Mcf/D at an average depth of 10,125 feet. This rate is below the maximum rate of 693 Mcf/day permitted by § 271.703(c)(2)(i)(B) of the regulations.

Wyoming reports that production data from wells completed in certain lands within the recommended area indicate stabilized production rates in excess of the maximum permitted rate. This "excess production" is purportedly due to native fracture systems which are sporadic and of limited areal extents. Wyoming has excluded these lands from its recommendation.

3. *Oil Production.* Wyoming briefly describes a laboratory phase determination study in which gas and liquid samples from five Mesaverde producing wells were collected. The laboratory test data confirmed that the hydrocarbon liquids in the combined well stream existed as a single phase at reservoir conditions. Thus, there is very little chance that a well completed in the Mesaverde Formation will produce in excess of 5 barrels of oil per day prior to stimulation.

4. *Infill Drilling.* No portion of the Mesaverde Formation was authorized to be developed by infill drilling prior to the date the recommendation was made by Wyoming.

III. Conclusion

The Commission has reviewed Wyoming's recommendation and the comments received in support thereof, and finds that the recommendation complies with the requirements of § 271.703(c)(3) of the regulations, concerning the contents of the recommendation. The Commission concurs with Wyoming's assertion, based on the consideration of the record which Wyoming submitted, that the Mesaverde Formation meets all the requirements for designation as a tight formation set forth in § 271.703(c)(2)(i), and should be designated as a tight formation.

IV. Effective Date

The Commission hereby makes the amendment to its regulations effective upon the date of issuance of this order. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. Therefore, good cause exists to waive the thirty day notice period preceding the effective date of rule.

(Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. 3101–3432; Administrative Procedure Act, 5 U.S.C. 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective November 14, 1980.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,208]

45 F. R. 76675 (November 20, 1980)

18 CFR Part 271

[Docket No. RM79-76 (Colorado-2); Order No. 111]

Ceiling Prices

Issued: November 14, 1980.

AGENCY: The Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions that present extraordinary risks or costs.

Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high cost gas subject to an incentive price (18 CFR 271.703). The rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Colorado Oil and Gas Conservation Commission that the Mancos "B" Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: November 14, 1980.

FOR FURTHER INFORMATION CONTACT:

Leslie Lawner, Federal Energy Regulatory Commission, Room 4308B, 825 North Capitol Street, NE, Washington, D.C. 20426 (202) 357-8299.

Victor Zabel, Federal Energy Regulatory Commission, Room 6100C, 825 North Capitol Street, NE, Washington, D.C. 20426 (202) 357-8559.

SUPPLEMENTARY INFORMATION:

I. Background

On August 29, 1980, the Colorado Oil and Gas Conservation Commission (Colorado) submitted to the Commission a recommendation, in accordance with § 271.703 of the Commission's regulations, that the Mancos "B" Formation underlying specified lands in Garfield and Rio Blanco Counties, Colorado, be designated as a tight formation in the Commission's regulations. On September 23, 1980, a Notice of Proposed Rulemaking was issued by the Director of the Office of Pipeline and Producer Regulation (OPPR) in Docket RM79-76 (Colorado-2) (45 FR 65607, October 3, 1980), to determine if Colorado's recommendation that the Mancos "B" Formation be designated as a tight formation should be adopted. The Director of OPPR issued the notice pursuant to the authority delegated to him by Order No. 97, Docket No. RM80-68, issued on August 1, 1980 (45 FR 53456, August 12, 1980).

Interested persons were given until October 23, 1980, to submit written comments and information concerning Colorado's recommendation. No party requested a hearing in this matter, and no hearing was held.

II. Discussion

The Commission, on February 20, 1980, issued an Interim Rule in Docket No. RM79-76 establishing a procedure for designating tight formations and for qualifying gas wells completed in those formations for the section 107 high-cost gas incentive price. The procedures and requirements delineated in the Interim Rule were not significantly changed in the Final Rule issued by the Commission in this docket on August 15, 1980 (Order No. 99). In this rule, the Commission delegated the initial responsibility for identifying potentially qualifying tight formations to each jurisdictional agency. The rule requires jurisdictional agencies to establish procedures and conduct their own investigations to identify tight formations within their own jurisdictions that meet the guidelines established by the Commission. The jurisdictional agencies will then submit written recommendations to the Commission that particular formations or portions thereof be designated as tight formations.

On August 29, 1980, Colorado submitted a recommendation that a portion of the Mancos "B" Formation in Colorado be designated as a tight formation, based upon the finding that the recommended formation meets the guidelines specified in § 271.703(c)(2)(i).

The portion of the Mancos "B" Formation which Colorado is recommending for designation as a tight formation is regionally located approximately midway between Grand Junction and Rangely, Colorado, and straddles the Rio Blanco-Garfield County line, from the Utah-Colorado state line east to the Douglas Pass and Baxter Pass Unit areas. The area consists of approximately 195,200 contiguous acres. Of the total acreage, approximately 95.9% of the land is federal land, 4% is fee and the remainder is state land. The United States Geological Survey, Central Region, advised in a letter dated August 26, 1980, that it concurs with Colorado's recommendation.

A. *Comments.* Comments on the proposed rule were received from two parties. The parties expressed support for the recommendation.

B. *Guidelines for Designation.* In § 271.703(c)(2)(i) of the regulations, the Commission has established guidelines which a formation must meet to be designated as a tight formation. These are:

(1) The average *in situ* gas permeability throughout the pay section is expected to be 0.1 millidarcy or less;

(2) The stabilized production rate, against atmospheric pressure, of wells completed for production in the formation, without stimulation is not expected to exceed production rates delineated in the table in § 271.703(c)(2)(i)(B) of the regulations;

(3) No well drilled into the recommended formation is expected to produce, without stimulation, more than five barrels of crude oil per day.

In addition, the final regulations require that any formation or portion thereof which has been authorized to be developed by infill drilling prior to the date of recommendation be excluded from the recommendation, if the jurisdictional agency has information which in its judgment indicates that such formation or portion thereof can be developed absent the incentive price for tight formation gas.

Colorado's submission is based on an analysis of geologic, engineering and production data generated from information concerning 56 wells which have penetrated the Mancos "B" Formation within the specified area. Pertinent data are arithmetic averages from the data base wells. These averages are as follows:

(1) The average *in situ* gas permeability throughout the pay section is expected to be .01 millidarcy;

(2) The expected stabilized production rate, against atmospheric pressure, of wells completed for production in the Mancos "B" Formation, without stimulation, is zero; and

(3) No wells drilled into the Mancos "B" Formation are expected to produce crude oil.

Colorado reports in its recommendation that no portion of the recommended formation was authorized to be developed by infill drilling prior to the date the recommendation was made by Colorado.

Colorado's submission also contained a description of the casing design of wells drilled in the specified area. Colorado concluded that the casing design is in conformance with State Rule No. 317, and is sufficient to protect all fresh water aquifers located above the Mancos "B" Formation. Colorado's conclusion is supported by correspondence from the Colorado Office of the State Engineer, Water Resources Investigation Branch. This information is included in the recommendation to satisfy the requirement found in § 271.703(c)(3)(iv), that the recommendation contain a report of the extent to which existing State and Federal regulations will assure development of the recommended formation will not adversely affect any fresh water aquifers. The Commission has reviewed Colorado's submission and has concluded that the designation of the recommended formation is not a major Federal action significantly affecting the quality of the human environment because significant impact to potable or potentially potable underground water by development of the Mancos "B" Formation will not occur.

III. Conclusion

The Commission has reviewed Colorado's recommedation and the comments received in support thereof, and finds that the recommendation complies with the requirements of § 271.703(c)(3) of the regulations, concerning the contents of the recommendation. The Commission concurs with Colorado's assertion, based on the consideration of the record which Colorado submitted, that the Mancos "B" Formation meets all the requirements for designation as a tight formation set forth in § 271.703(c)(2)(i), and should be designated as a tight formation.

IV. Effective Date

The Commission hereby makes this amendment to its regulations effective upon the date of issuance of this order. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. Therefore, good cause exists to waive the thirty day notice period preceding the effective date of the rule.

(Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301–3432 Administrative Procedure Act, 5 U.S.C. § 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, Code of Federal Regulations, is amended as set forth below, and the amendment is issued as a final regulation, effective November 14, 1980.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,209]

45 F. R. 76676 (November 20, 1980)

18 CFR Part 271

[Docket No. RM80-14; Order No. 68A]

Ceiling Prices; Order Clarifying Order No. 68, Granting in Part and Denying in Part Rehearing of Order No. 68, and Amending Regulations in Subparts E, F, and K

Issued: November 10, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Order on rehearing of final rules.

SUMMARY: On January 18, 1980, the Commission issued, as Order No. 68, final regulations for pricing natural gas sold under existing and successor intrastate contracts and intrastate rollover contracts. 45 FR 5678 (Jan. 24, 1980). Petitions to rehear this order were received which raised several issues. In Order 68–A, the Commission responds to most of the issues by amending its regulations to (1) permit a seller of intrastate gas to receive production-related cost add-ons under section 110 of the NGPA for costs not allocated to the seller under the terms of the sales contract as it existed on November 9, 1978 and (2) to remove the regulatory proscription that successor contracts may not provide for an earlier delivery date than provided for under the existing contract. Issues as to the role of State severance taxes on intrastate ceiling prices raised by the petitions are to be dealt with under final rules issued in Docket No. RM80–21.

EFFECTIVE DATE: The regulations are to be effective for deliveries made on or after December 1, 1980.

FOR FURTHER INFORMATION CONTACT: Mr. Scott Koves, Office of the General Counsel, Federal Energy Regulatory Commission, Room 4016 G, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357–8317.

SUPPLEMENTARY INFORMATION:

I. Introduction

On January 18, 1980, the Commission issued final regulations amending Subparts E and F of Part 271 relating to first sales under existing (and successor) intrastate contracts, and intrastate rollover contracts.[1] Several timely petitions for rehearing of those final regulations were filed.[2] Having considered the issues raised in those petitions, the Commission now amends its regulations in Subparts E and F, and in Subpart K (relating to section 110 allowances for certain production-related costs) to permit sellers subject to Subparts E and F to apply for allowances for production-related costs which were not allocated to the seller under the existing intrastate contract. In addition, provisions in the regulations barring modification of a delivery date are rescinded.

II. Specifications of Error and Discussion

A. Contract Modifications That Shift Costs Previously Allocated to the Seller.

The general rules in §§ 271.505(a)(1) and 271.604(a) preclude, after November 9, 1978, the modification of any contract subject to sections 105 or 106(b) of the Natural Gas Policy Act of 1978 (NGPA) that has the effect of shifting to the purchaser any production-related costs that were allocated to the seller under the existing intrastate contract. An exception is provided for new purchasers.

Shell, *et al.*, and other assert that the Commission is without authority under the NGPA to preclude modification of terms of intrastate contracts other than those that determine "price." They argue that Title I of the NGPA only restricts prices and, further, that the definitions of a "successor" or "rollover" contract (sections 2(14) and 2(12) of the NGPA) specifically permit changes in any terms of the prior contract. Finally, Tenneco, *et al.*, states that nothing in section 110(a)(2) prevents a purchaser from assuming production-related costs without reducing the price. Accordingly, they argue that the Commission has no authority to prohibit the shifting of production-related costs.

Further, Tenneco, *et al.*, and others contest § 271.505(a)(1) and § 271.604(a) because those sections preclude modifications in which no "shifting" of costs previously allocated to the seller occurs. They contend that nothing should prevent the purchaser from agreeing to pay for new production-related costs, such as compression, if no party to the existing intrastate contract was previously obligated to pay for such compression.

The Commission is still of the opinion that to give proper effect to sections 105 and 106(b), production-related costs that were allocated to the seller under the existing intrastate contract may generally not be shifted to the purchaser. However, the regulations were not intended to imply that a purchaser could not incur the financial burden of undertaking production-related activities that the seller had no obligation to bear under the existing contract.

Petitioners correctly note that the focus of Title I of the NGPA is on prices paid for gas. However, section 110 of that Act demonstrates that Congress recognized and was concerned that any production-related costs reimbursed by the purchaser are part of the price paid by the purchaser to obtain the gas. Rather than determine that all production-related costs must be reimbursed within the constraints of the maximum lawful prices, Congress gave the Commission in section 110 the discretion to determine that certain production-related costs, if borne by the seller, could be reimbursed without exceeding the maximum lawful price.

The section 105 and 106(b) maximum lawful prices may be distinguished from other maximum lawful prices because they are determined by the terms of contracts as they existed on November 9, 1978 (the date of enactment of NGPA), and therefore provide reimbursement for production-related costs borne by the seller according to the terms of contracts. Any production-related costs borne by a purchaser under the terms of a contract are part of the price paid to obtain the gas. No costs borne by the seller under the existing contract may be shifted to the purchaser without increasing the economic burden, or the total price, paid by the purchaser. Accordingly, the Commission believes that when Congress used the terms "contract price" and "price under the terms of the existing contract" in section 105, it did so with the understanding that each such negotiated "price" related to a specific set of obligations allocated between the parties as of November 9, 1978. The price ceilings established under section 105 only have meaning when set in the context of all terms of the existing contract in effect on November 9, 1978. Thus, production-related costs allocated to the seller under the existing intrastate contract may not be shifted to the purchaser, without exceeding the maximum lawful price under section 105.

The general rule that production-related costs allocated to the seller under the existing contract may not be shifted to the purchaser is retained in the regulations with some modification as discussed below. The same general rule respecting intrastate rollover contracts contained in Subpart F of the Commission's regulations has been modified to more closely parallel the rule contained in Subpart E.

The Commission is not convinced by petitioners' assertions that the statutory definitions of "successor" [3] and "rollover contract" [4] permit modifications which alter the distribution of economic burdens under the contract. Sections 2(14) and 2(12) only determine what may be considered a "successor" or "rollover" contract. They do not determine what rate may lawfully be charged under section 105.

B. *The Allocation of New Costs.* Given the rule that production-related costs allocated to the seller as of November 9, 1978 may not be shifted to the purchaser, the next question that arises (and one with which the petitioners were particularly concerned) is how to treat situations in which entirely new production-related costs are to be incurred. This could occur, for instance, when the gas needs to be processed to a higher quality standard, or subject to more compression before entering the pipeline. Under section 110(a)(2) a seller may recover certain production-related costs in addition to the maximum lawful price without being considered to have exceeded the maximum lawful price. Section 110(a)(2) of the NGPA provides, with exceptions not here relevant, that:

> [A] price for the first sale of natural gas shall not be considered to exceed the maximum lawful price applicable to the first sale of such natural gas under this subtitle if such first sale price exceeds the maximum lawful price to the extent necessary to recover * * * any costs of compressing, gathering, processing, treating, liquefying, or transporting such natural gas, or other similar costs, borne by the seller and allowed for, by rule or order, by the Commission.

In the interim rules of December 1, 1978, that implemented this portion of the NGPA, sales made under sections 105 and 106(b) of the NGPA were expressly excluded from any application procedure for section 110 add-ons.[5] As we expressed it then: "the existing contract provisions reflect the allocation of costs of production as they were contemplated by the parties at the time the contract was negotiated"; to permit an increase for production-related costs, "would have the effect of increasing the total costs borne by the purchaser for acquiring the very same commodity as he was acquiring for a lower price before [the] date of enactment." [6]

On July 25, 1980, the Commission issued Order No. 94 amending those provisions of its interim regulations that deal with the production-related costs of section 110(a)(2).[7] Among the provisions of those regulations not substantively amended was the exclusion of intrastate sales from applications under section 110.[8] In Order No. 94, the Commission stated that, because petitions to rehear Order No. 68 raised issues concerning the exclusion, and because there was a relationship between the exercise of the Commission's discretion under section 110 and the pricing of intrastate sales, the proper place to consider the prohibition against intrastate sales applications for section 110 add-ons would be in a Commission order granting or denying rehearing of Order No. 68.[9]

Comments to the interim regulations of December 1, 1978, and petitions to rehear Order No. 68, have asserted that the Commission's regulations excluding intrastate sales from the production-related cost application procedures, together with regulations under Subparts E and F that generally prohibit contract modifications to shift production-related costs to purchasers of intrastate gas, are discriminatory and provide disincentives for sellers to incur costs to upgrade services. According to these petitions, the consequences of both sets of rules would be either degradation in services or early abandonment of wells. To prevent these results, the petitioners suggested that we permit sellers to apply for section 110 add-ons (for production-related costs borne by them) or to eliminate §§ 271.505 and 271.604 and allow contract amendments to permit production-related costs allocated to sellers to be incurred by purchasers.

Other petitioners charged that the exclusion of intrastate gas sales from the section 110 provisions was arbitrary and, in light of existing contracts or allowances, prejudicial. These comments claimed that exclusions violated the intent of section 110 because that section was to apply to all ceiling prices and did not expressly exclude any type of first sale from its provisions. Finally, petitioners also raised the question of how production-related costs which neither party (purchaser or seller) has previously undertaken should be treated.

The key characteristic on which the Commission relied in Order No. 68 was the negotiated nature of section 105 ceiling prices. Unlike other sections under Title I of the NGPA, the section 105 ceiling prices have a direct relationship to individual circumstances of the particular sales transactions to which they apply. As we have found above, the section 105 maximum lawful price is inextricably tied to the production-related costs allocated between the parties to the existing intrastate contract. In section 105, we believe Congress sought to bind the parties to these freely negotiated agreements which, on an individualized basis, provide remuneration for the costs of whatever production-related expenditures the seller has bound himself to incur. Therefore, we believe that it would be inappropriate to permit sellers of natural gas under Subparts E and F of the regulations to apply for production-related costs as add-ons for these types of costs. However, to the extent this rule results in special hardship, inequity or an unfair distribution of burdens, application for an adjustment from its constraints may be made pursuant to section 502(c) of the NGPA under § 271.1106 of the Commission's regulations.

On the other hand, with respect to the incurrence of production-related costs that were not allocated to the seller under the terms of the existing contract, the Commission is convinced that section 110 production-related cost allowances would be appropriate. We reach this conclusion for two reasons. First, to the extent the costs are allowed, the purchaser may be paying more to obtain the gas but he is not obtaining gas of the same value. In other words, he is obtaining more than he bargained for under the existing intrastate contract. Under the production-related cost allowance the difference in the price would represent reimbursement only for the cost of the different service and would not represent reimbursement for any economic burdens allocated to the seller under the contract as it existed on November 9, 1978. To not permit an application for such an allowance would, in effect, prevent parties from responding to changed requirements.

This point raises the second reason for permiting applications for production-related cost allowances for new services. Nothing in the NGPA indicates that Congress intended to prevent, even in the case of section 105 gas, modification of terms of contracts so long as the section 105 maximum lawful price is not violated. In other words, so long as the purchaser pays the same price for the services to which he had a right under the existing intrastate contract, the contract may be amended to provide reimbursement for new services. To permit a seller to recover production-related costs not allocated to him under the existing intrastate contract, the regulations in Subparts E (relating to existing and successor intrastate contracts), F (relating to rollover intrastate contracts) and K (relating to section 110 allowances) have been amended.

In changing the regulations to permit a seller of intrastate gas to apply for new production-related costs, the Commission should be clearly understood as making this change prospective only. A seller will not be permitted to add on costs retroactively to December 1, 1978. There are two reasons for this. First, given the discretionary nature of section 110, the

Commission is not required to grant the applied for add-on retroactively. Second, no strong policy exists to do so; rather, a countervailing policy exists not to permit retroactive collection. Since December 1, 1978, the Commission's regulations have permitted no section 110 add-ons for sellers of intrastate gas. Seller and purchaser alike have operated under those regulations. What we do today under this order marks an important change in these regulations, one which neither sellers nor purchasers expected. To permit the application of the new regulations respecting production-related cost add-ons to have retroactive effect would therefore be, in our view, unfair to purchasers and unwarranted.

The amendments in Subparts E and F (§§ 271.505 and 271.604 respectively) prohibit only the shifting of production-related costs that were allocated to the seller under the existing intrastate contract as it existed on November 9, 1978. The regulations never prohibited a purchaser from incurring any costs the seller had no obligation to bear under the existing contract, and they no longer prohibit the seller from applying for an allowance for production-related costs that were not allocated to the seller under the existing intrastate contract.[10] When the applicable maximum lawful price under section 106(b) is determined in reference to the price paid under the expired contract, reimbursement authorized and collected pursuant to Subpart K shall not be included.

To ascertain whether, and to what extent, production-related costs are reimbursed under the sections 105 and 106(b) maximum lawful price the Commission will refer to the terms of the intrastate contract as they existed on November 9, 1978. The Commission will defer to the parties, or when necessary State law, to interpret the contracts. While the matter of contract interpretation is to be left to the parties, the parties cannot ascribe an interpretation to their contract which contradicts or is inconsistent with the terms of the contract as they were in effect on November 9, 1978.[11] To the extent the terms of the contract that existed on November 9, 1978, do not explicitly or by implication allocate to the seller the burden of undertaking the service, the contract may be amended to provide for reimbursement of the expenses incurred in rendering such service.

To permit those who sell gas under the provisions of sections 105 and 106(b) to apply for production-related costs that were *not* allocated to the seller under the terms of the existing contract (which serves as a basis for the first sale ceiling price) several amendments are made to Subpart K of the Commission's regulations. First, § 271.1104(b)(1) is amended to permit those selling under Subpart E or F of Part 271 (sales made under existing intrastate contracts, and successors and rollovers of such contracts) to make application under Subpart K for production-related costs not allocated to the seller under the existing intrastate contract which was applicable to the gas on November 9, 1978. Because the section (§ 271.1104(b)) would no longer exclude intrastate gas sales from the application process of Subpart K, the title to paragraph (b) is changed.

Second, the provisions of § 271.1105(a) respecting information to be supplied in applications for the determination of production-related costs to be added on are amended. A requirement has been added that, for sales made under Subparts E and F for which an application is made, both seller and purchaser must agree that the production-related costs that are the objects of the application are costs that were not allocated to the seller under the terms of the intrastate contract which was applicable to such gas on November 9, 1978. An attestation to that mutual interpretation must be filed. In addition, a copy of the existing contract (or the expired contract if the sale is a rollover) must be supplied.

Finally, § 271.505(b) is amended by the addition of a new subclause to provide that the prohibitions on modifying contracts contained in § 271.505(a) does not preclude the seller from recovering production-related costs authorized under Subpart K.

C. *Delivery Date—§ 271.505(a)(2).* Section 271.505(a)(2) states that, as a general rule, no successor to an existing intrastate contract or modification executed after November 9, 1978, of an existing intrastate contract, may provide for an earlier date for deliveries than provided for under the existing contract.

Tenneco, *et al.*, asserts that this provision will impair the authority of state commissions to determine intrastate pipeline deliverability; that it would force an intrastate pipeline to curtail; and, that it could prohibit a producer from increasing deliveries from a competitive reservoir.

This was not our intent. The basic purpose of § 271.505(a)(2) was to prevent the back-dating of contracts or delivery schedules to obtain higher rates or otherwise circumvent the Act. It was not to prohibit the parties from prospectively modifying their schedule of deliveries as long as such modification would not otherwise effect a circumvention of the NGPA. However, the Commission believes that this is clear enough from the statute, and, accordingly has deleted paragraph (a)(2) from § 271.505.

D. *The Exception for New Purchasers—§§ 271.505(b) and 271.604(b).* Sections 271.505(b) and 271.604(b) create a limited exception to the general rule in paragraph (a) of each rule by providing that nothing in the general rule prohibits a contract modification to shift production-related costs to a new purchaser in order for that person to take delivery of the gas subject to the intrastate contract. In Order No. 68 we clarified the exception as being limited to only those additional costs necessary for initial hook-up with a new purchaser.[12]

The Railroad Commission of Texas (Railroad Commission) asserts that the Commission erred by limiting the application of §§ 271.505(b) and 271.604(b) to new purchasers and by failing to limit adequately the type of expenses which a new purchaser could agree to pay. The Railroad Commission argues that, in fact, the exception works a discrimination against intrastate purchasers because the existing intrastate market structure includes many fields served by only one intrastate line. In its view, the exception will permit interstate pipelines to displace existing intrastate purchasers which will ultimately increase the cost to consumers. United Texas Transmission Corporation also argued that there is no basis for discriminating between new and old purchasers.

The Commission disagrees. The fundamental purpose of these special rules is to expedite the transfer of deliveries from one purchaser to another with a minimum of disruption in service. With the absence of Natural Gas Act-type service obligations, the only other factor protecting continuity of intrastate service is the enforcement of the contract by the parties. Sections 271.505(b) and 271.604(b) endeavor to provide a mechanism to expedite the transition to a new purchaser so that such service is not interrupted or terminated.

Furthermore, in answer to the claim that these rules effect a discrimination, it is the Commission's view that there is no real discrimination effected against the existing purchaser. These rules only relate to new hook-up costs, costs that an existing purchaser would not be expected to experience. Indeed, these rules eliminate the discrimination against a new purchaser that is inherent in any rule that would proscribe amendments relative to new hook-up costs.

The Commission recognizes that the shifting of any cost arguably violates the ceiling price restrictions of sections 105 and 106(b), but believes that the nature of new hook-up costs in the context of sections 105 and 106(b) first sales permits them to be deemed "new costs" which do not involve the kind of cost "shifting" proscribed by the general rules of §§ 271.505(a) and 271.604(a).

The cost allocations between the seller and the buyer on date of enactment of the NGPA were established in the factual context of a sale to the existing purchaser. To the extent that purchaser remains the same, those existing cost allocations, having become embodied in the ceiling rate restrictions, may not be altered.

However, when a changeover to a new purchaser occurs, that existing factual context in which the original contract was negotiated may change in one important respect. The need for new investments not contemplated by the parties (and, indeed, not even relevant to the original transaction) may arise. These costs would not have been within the scope of the original negotiations. The original parties would be expected to have negotiated only with respect to costs relevant to their sale; not to a future sale involving a different purchaser. None of the subject costs would have been allocated to the seller on date of enactment. In that sense, these costs may be deemed "new" costs. A modification of the existing contract relative to these costs should not be considered to involve a proscribed cost "shift."

But, as we clarified in Order No. 68, these special exemptions in the case of new purchasers are only intended to cover the additional new costs required to effect an initial hook-up with a new purchaser. To the extent that a particular aspect of the seller's service obligation is not required to change, then the cost of that unchanged service may not be shifted.[13] Furthermore, the Commission wishes to express a strong caveat that these special exemptive rules are not intended to allow a seller to circumvent section 105 or 106(b) by requiring the new purchaser to incur unnecessary, duplicative costs. Only such additional costs as are physically necessary to hook up to the new purchaser are contemplated by the special exemptions.

E. *Intrastate Rollover Contracts—the definition of a rollover contract in section 2(12).* Cabot Corporation apprehends a problem in Order No. 68 as to whether a new contract or amendment must be entered into to fulfill the requirements of an intrastate "rollover contract" or whether a rollover occurs simply upon the expiration of the prior contract. Cabot also asserts that the Commission, by its interpretation of a rollover, has preempted the possibility of any contract being deemed a "successor" contract.[14] Cabot suggests that the Commission provide that the parties may lengthen the term of the existing contract to prevent a rollover from occurring.

Cabot misapprehends Order No. 68. As we described in that Order, there are two prerequisites to a "rollover" in section 2(12): (a) the previous contract must have expired at the end of a fixed term according to the terms of the contract in effect on date of enactment, *and* (b) a new contract or amendment must be entered into on or after date of enactment.

Thus, a "successor" to an existing intrastate contract as defined in section 2(14) of the NGPA can, in fact, occur. A "successor" includes a contract that fails to meet the first of the two foregoing prerequisites. For example, if the primary term of an existing intrastate contract is due to expire January 1983, a new contract entered into in June of 1979 would be a "successor" contract. The first prerequisite was not met because the previous contract had not expired at the end of its fixed term.

Finally, section 2(12) of the NGPA expressly prohibits any term extension that takes effect on or after date of enactment from affecting the date the "fixed term" of the previous contract is deemed to have "expired." Accordingly, a term extension entered into on or after the date of enactment of the NGPA cannot serve to prevent a rollover from occurring, as Cabot suggests.

Union, *et al.*, seeks clarification of whether a rollover occurs only upon execution of the rollover contract or upon an earlier "effective date" agreed to by the parties. More specifically, Union, *et al.*, raises a case in which the existing intrastate contract expires and is apparently terminated but a "time gap" occurs before a rollover contract is executed. During the interim gap, sales may or may not continue. Union, *et al.*, asserts that the parties should be allowed to retroactively establish the effective date of the rollover contract so that the inflation adjustments provided for in section 106(b) of the NGPA may apply continuously during that gap in order that the income from the sale will not diminish in "real value" terms.

The language at section 106(b)(1)(A) established a maximum lawful price equivalent to "the maximum price paid under the expired contract * * * in the case of the month in which the *effective date* of such rollover contract occurs" (emphasis added), plus, for any month thereafter, an inflation adjustment factor. As argued by Union, section 106(b) does not preclude the possibility that a "rollover contract" may be made retroactively effective, and, therefore, "entered into" prior to the date a formal rollover contract is executed. As the Commission noted in Order No. 68, the date a rollover contract has been "entered into" depends upon various factors. Interpretations regarding individual cases such as that presented by Union may be requested of the General Counsel pursuant to § 1.42 of the Commission's regulations.

F. *The Definition of "Price Under the Terms of the Existing Contract"—§ 271.504(b).* Section 271.504(b) defines the "price under the terms of the existing contract" to include:

> Any State severance taxes which would have been levied on gas subject to the contract (whether such taxes would have been borne by the seller or reimbursed by the purchaser).

Shell, *et al.*, argue that this definition is in direct conflict with section 110(a)(1) insofar as it may prohibit the collection of the difference between the amount of tax reimbursed to the seller under a tax provision of the contract and the total amount of tax levied on the sale. Shell, *et al.*, contends, for various reasons, that the "price under the terms of the existing contract" should be redefined to refer only to the "price" and not the "tax" provisions of the contract. The Commission has also received numerous inquiries concerning the definitions of these terms.

Concurrently with Order No. 68, we issued a notice of proposed rulemaking in Docket No. RM80-21.[13] There we called for comments on the question of the treatment under section 110 of State severance taxes in the case of sales made under sections 105 and 106(b) of the NGPA. All issues raised by Shell, *et al.*, and other inquiries concerning State severance taxes shall be considered when the Commission issues final regulations in Docket No. RM80-21 and will not be resolved here. Upon issuance of the final rule in Docket No. RM80-21, any further objections to the treatment of State severance taxes may be raised in petitions for rehearing of that final rule.

III. Summary of Major Amendments

Sections 271.505 and 271.604 have been amended to prohibit the shifting of production-related costs allocated to the seller under the existing intrastate contract. An exception is provided in both sections for costs necessary for a new purchaser to take delivery of the gas. In addition, those sections and § 271.1104 have been amended to permit a seller to apply under Subpart K of the Commission's regulations for an allowance for production-related costs not allocated to the seller under the intrastate contract. And § 271.1105 has been amended to require that certain information and attestations be supplied when application is made for those costs. Finally, the provision of § 271.505(a)(1) barring successor contracts from providing for an earlier date for deliveries than provided for under the existing contract is removed.

IV. Effective Date

The amendments made by this order relieves restrictions that have been placed on sellers who price their gas under the provisions of sections 105 and 106(b) of the NGPA. Because of this, good cause exists to make these amendments effective at the earliest practicable date. Because the amendments go to pricing of natural gas under the NGPA, and because such pricing is, as a general matter, adjusted monthly, that date is December 1, 1980. Therefore, the changes set out in this order shall be effective for deliveries of natural gas made on or after December 1, 1980.

(Administrative Procedure Act, 5 U.S.C. § 553, Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301-3432)

In consideration of the foregoing, Subparts E, F and K of Part 271 are amended as final regulations as set forth below, effective for deliveries made on or after December 1, 1980. Except insofar as we have amended the regulations, and reserved for further consideration the issues relating to the treatment of State severance taxes, all other issues raised in the petitions for rehearing are denied.

By the Commission.

Kenneth F. Plumb,
Secretary.

—Footnotes—

[1] Order No. 68, "Final Regulations Under Sections 105 and 106(b) of the Natural Gas Policy Act of 1978", Docket No. RM80-14 (issued Jan. 18, 1980); 45 FR 5678 (Jan. 24, 1980).

[2] Undersigned Producers (Tenneco Oil Company, *et al.*); Union Oil Company of California, *et al.*; Phillips Petroleum Company; Railroad Commission of Texas; Undersigned Producers (Shell Oil Company, *et al.*); Cabot Corporation; and United Texas Transmission Company.

[3] Section 2(14) of the NGPA defines "successor to an existing contract" to mean: "any contract, other than a rollover contract, entered into on or after the date of the enactment of this Act, for the first sale of natural gas which was previously subject to an existing contract, whether or not there is an identity of parties or terms with those of such existing contract."

[4] Section 2(12) of the NGPA defines the term "rollover contract" to mean "any contract, entered into on or after the date of the enactment of this Act, for the first sale of natural gas that was previously subject to an existing contract which expired at the end of a fixed term (not including any extension thereof taking effect on or after such date of enactment) specified by the provisions of such existing contract, as such contract was in effect on the date of the enactment of this Act, whether or not there is an identity of parties or terms with those of such existing contract."

[5] "Natural Gas Policy Act of 1978: Interim Regulations" Docket No. RM79-3 (issued Dec. 1, 1978), 43 FR 56448 (Dec. 1, 1978).

[6] *Id.* at 77-78, 43 FR at 56469.

[7] Order No. 94, "Regulations Implementing Section 110 of the Natural Gas Policy Act of 1978 and Establishing Policy Under the Natural Gas Act" Docket No. RM80-47 (issued July 25, 1980), 45 FR 53099 (Aug. 11, 1980).

[8] *Id.* at 82, 45 FR at 53115. The exclusion is at 18 CFR § 271.1104(b)(1); prior to Order No. 94, it was codified at 18 CFR 271.1105(b)(1) (1979).

[9] *Id.* at 30; 45 FR at 53107.

[10] In addition, the citations to the definition of "production-related costs" that appear in §§ 271.505(a) and 271.604(b) have been changed to conform to the modifications of Order No. 94 that place that definition under § 270.102(b)(17).

[11] *See* Order No. 23, "Amendment and Clarification of the Commission's Interim Regulations, Implementing the Natural Gas Policy Act of 1978 and Regulations Under the Natural Gas Act", Docket No. RM79-22 at 53, (issued Mar. 13, 1979) 44 FR 16895, 16904-905 (Mar. 20, 1979).

[12] Order No. 68, note 4 *supra* at 13, 45 FR at 5680.

[13] For example, if the new sale requires the connection of a lateral line to seller's existing gathering system the seller may not shift the cost of its entire gathering system to the new purchaser. The new purchaser may pick up only the additional costs necessitated by the hook-up, *i.e.*, the cost of the lateral line and necessary interconnection facilities.

[14] In doing so, Cabot apparently ignored the following words of Order No. 68: "a rollover can 'occur' even if a contract term extension *which took effect on or after November 9, 1978*, has not yet expired." Order No. 68, note 1 *supra* at 22, 45 FR at 5682 (emphasis supplied). When the italicized words are considered, it is clear that this statement does not eliminate either the requirement that pre-November 9, 1978, term extensions must expire before a rollover may "occur" or the requirement that a new contract or amendment must be entered into to cause a "rollover" to occur.

[15] Notice of Proposed Rulemaking, "Proposed Regulations Under Section 110 of the Natural Gas Policy Act of 1978," Docket No. RM80-21 (issued Jan. 18, 1980) 45 FR 5748 (Jan. 24, 1980).

[¶ 30,210]

45 F. R. 77421 (November 24, 1980)

18 CFR Parts 271, 273, and 274

[Docket No. RM80-50; Order No. 107]

High-Cost Natural Gas: Production Enhancement Procedures

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is establishing an incentive maximum lawful price under section 107 of the Natural Gas Policy Act of 1978 (NGPA) for certain

intrastate gas produced from wells on which production enhancement work has been performed. The rule establishes an incentive price for production enhancement gas equal to the lesser of the section 109 price or a price negotiated by the parties after November 9, 1978 in connection with the production enhancement work. This price is available for natural gas for which a maximum lawful price prescribed under section 105 of the NGPA is applicable. The rule defines "production enhancement work" to include ten different types of production enhancement techniques and establishes the procedures for determining whether natural gas qualifies for the incentive price.

EFFECTIVE DATE: December 15, 1980.

FOR FURTHER INFORMATION CONTACT:

Webster Gray, Office of Pipeline and Producer Rates, 825 North Capitol Street NE., Room 6000–B, Washington, D.C. 20426, (202) 357–8693

Roger Coven, Office of General Counsel, 825 North Capitol Street NE., Room 4013, Washington, D.C. 20426, (202) 357–9124

Issued November 13, 1980.

On July 25, 1980, the Federal Energy Regulatory Commission (Commission) issued a Notice of Proposed Rulemaking (45 FR 51219, August 1, 1980) to establish an incentive maximum lawful price under section 107 of the Natural Gas Policy Act of 1978 (NGPA) for certain intrastate gas produced from wells on which production enhancement work has been performed. The proposed incentive price was the *lesser* of the section 109 maximum lawful price or the negotiated contract price. The Commission proposed this incentive price in order to prevent loss of production from wells for which the existing intrastate contract prices permitted under section 105 of the NGPA are insufficient to encourage production enhancement work necessary to maximize or continue production.

We are now promulgating a final rule. During the course of this rulemaking we have reaffirmed our original, general purpose to encourage production of gas reserves that would not otherwise be produced. However, the Commission's lack of sufficient information respecting the economic impact of the proposed rule on the natural gas industry and consumers and our inability to elicit enough information during the comment period to permit us to predict the exact nature and extent of that impact dictate that we proceed with caution.[1]

Therefore, we have not extended the scope of the rule to include gas subject to sections 104 and 106(a),[2] *i.e.*, gas committed or dedicated to interstate commerce; or gas subject to section 106(b), *i.e.*, intrastate rollover contract gas. Nor have we increased the incentive price ceiling above the section 109 maximum lawful price, *i.e.*, the price applicable to gas not subject to any other section of Title I. We have also decided to retain those requirements in the rule that are essential to insure that the incentive price provided in this rule is available only when *necessary* to provide a *reasonable* incentive for production.[3] However, based on comments received during this rulemaking, we have extended the scope of this rule to add five production enhancement techniques to the five originally proposed.

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[1] Commission action in this regard commenced on June 13, 1979 with the issuance of a "Notice of Inquiry Regarding the Implementation of Section 107 (b) and (c) of the Natural Gas Policy Act of 1978" to identify categories of high-cost natural gas and correlative incentive prices. Docket No. RM79–44 (44 FR 34511, June 18, 1979). In response to a petition by the Sun Gas Company (Docket No. RM80–41, filed February 27, 1980), the Commission initiated Docket No. RM80–50 and in that docket, approved in principle on May 29, 1980, proposed a rule classifying natural gas resulting from production enhancement procedures as high-cost natural gas and specifying an incentive price. *See* Notice of Availability of the Staff Draft, Docket No. RM80–50 June 12, 1980 (45 FR 41449, June 19, 1980); and Memorandum to Public File: Informal Conferences with the Public to Discuss the Staff Draft, Docket No. RM80–50. A Notice of Proposed Rulemaking was issued in RM80–50 on July 25, 1980, and thirty day comment period was announced. Two public hearings were held following the comment period to receive oral comment.

[2] There are additional reasons for excluding section 104 and section 106(a) gas from the scope of this rule. *See* Discussion, *infra*.

I. Background

A. The Problem

Section 105 of the NGPA establishes maximum lawful prices for first sales of natural gas that was not committed or dedicated to interstate commerce on November 8, 1978, and that is sold under a contract that was in effect on November 8, 1978. Section 105 also covers sales of gas under successor contracts to such existing contracts. Maximum lawful prices in section 105 are referenced to the price or price terms of the contract on November 9, 1978.

Under section 105(b)(2), a producer whose contract price on date of enactment was above the maximum lawful price for "new" natural gas, *i.e.*, the section 102 price, is entitled to receive the higher of the section 102 price or his contract price, adjusted for inflation. If and when the section 102 price exceeds the contract price (adjusted for inflation), as a result of the effect of the additional section 102 growth factor,[4] the producer and purchaser can renegotiate the contract price up to the section 102 price.

Under section 105(b)(1), however, the producer whose contract price on November 9, 1978, was less than the section 102 price is only entitled to the *lower* of the section 102 price or the price under the terms of the contract as of November 9. Therefore, not only is the producer making sales subject to section 105(b)(11) denied the section 102 price, he is also prohibited from renegotiating the contract to obtain a price higher than that determined under the contract's terms on date of enactment. If the producer encounters production problems, he will be unlikely to correct those problems if the section 105(b)(1) price is insufficient to cover the costs of production enhancement work and also return a reasonable profit. Under such circumstances production will probably diminish and, at the point out-of-pocket expenses exceed revenues, the producer will be likely to abandon the well. The result of either abandonment or a decrease in the rate of production may be permanent loss of the unrecovered gas.

The origins of this pricing problem are unique to section 105[5] and derive from the imposition of federal regulation on contractual relationships that responded to and were created in a very different regulatory environment. The only previous limitations on renegotiation of intrastate contract prices were state law and any restrictions contained in the contract itself. Contracts frequently contained no pricing provision to account for production problems that might develop during the course of producing a well but that were unforseen at the time the contract was entered into. However, if a purchaser deemed it in his best interests to compensate a producer for correcting such problems in order to obtain additional gas supplies he was free to renegotiate the contract. Thus, prior to the NGPA, a purchaser could assume that he would be able to protect his interests by using renegotiation as a safety valve in such situations.

The advent of the NGPA vitiated that assumption. In section 105(b)(1) Congress "froze" intrastate contract prices in order to protect purchasers of very low-priced intrastate gas from the increase in bargaining power accruing to intrastate producers under the NGPA as a result of their ability to sell in the interstate, as well as the intrastate, market free of prior regulatory restraint.[6] However, prohibiting intrastate producers from charging increased prices also restricts their intrastate purchasers. A purchaser willing to increase the price he pays for gas by providing revenues for production enhancement work in order to insure an increase in gas supply is prevented from agreeing to pay that higher price unless the contract provides, by its terms, a mechanism for increasing the price above that in effect on date of enactment.

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[3] Under section 107 the Commission is empowered to designate certain natural gas as "high cost natural gas" if it is produced under conditions that present extraordinary risks or costs and to establish prices higher than the otherwise applicable maximum lawful price to the extent necessary to provide reasonable incentives for the production of such gas.

[4] In addition to being adjusted by the monthly inflation factor the section 102 maximum lawful price is also escalated monthly by a growth factor.

[5] *See* discussion of section 106(b) *infra* in Section B.

This legal restriction confronting producers of gas subject to section 105 does not apply to producers of interstate gas, *i.e.*, gas that is subject to sections 104 and 106(a).[7] The maximum lawful prices for those sections are based on the just and reasonable rates under section 4 of the Natural Gas Act as of April 1, 1977, adjusted for inflation. If the revenues produced by such prices are inadequate, the problem is attributable to the rate making methods used under the Natural Gas Act. Buyers and sellers who contracted in that regulatory environment are assumed to have taken these price restrictions into account when deciding to proceed with a transaction. Because any inadequacies in the maximum lawful prices for section 104 or section 106(a) derive from a different regulatory context than those in the section 105 price, we will not deal with them under this rule.[8]

B. The Commission's Solution

The Congress has authorized this Commission to permit higher maximum lawful prices if necessary to privide reasonable incentives to encourage production of gas that is produced at extraordinary risk or cost.[9] The Commission has decided that an incentive is necessary in order to induce a producer of section 105 gas to perform production enhancement work. We have determined to permit an incentive equal to the lesser of the price under section 109, (a price category reserved by the Congress as a kind of residual or catch-all) or the renegotiated price. The section 109 price as of November 1980 is $1.929.

Production enhancement work is performed in order to maintain or to increase production from a marginal well or to return an abandoned well to production.[10] Typical production enhancement operations such as re-entries, recompletions, or the addition of compression are not commonly regarded as presenting extraordinary risks or costs. In certain circumstances, however, cost becomes extraordinary because it cannot be recouped at the otherwise applicable section 105 price or because it is so high in relation to the price under the contract that the producer simply will not undertake the production enhancement operation in the absence of an incentive price. Nevertheless, the price necessary to induce a producer to perform these types of operations will prove, in almost every case, to be lower than the price that pipeline purchasers would pay for new supplies or that end users would pay for alternative fuels.

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[6] Section 601(a)(1)(A), denies Natural Gas Act jurisdiction to any natural gas not committed or dedicated to interstate commerce as of November 8, 1978.

[7] Section 104 of the NGPA provides maximum lawful prices for natural gas that was committed or dedicated to interstate commerce on November 8, 1978 and for which a just and reasonable rate under the Natural Gas Act was in effect on November 8, 1978 for the first sale of such gas.

Section 106(a) provides maximum lawful prices for natural gas that was committed or dedicated to interstate commerce on November 8, 1978 and that is sold under any "rollover contract. A rollover contract is any contract entered into on or after November 9, 1980 for the first sale of gas that was previously subject to a contract that expired at the end of a fixed term.

[8] We note that Congress has provided special repricing mechanisms for such gas in sections 104(b)(2) and 106(c). *See* note 10, *infra*.

[9] Section 503, entitled "DETERMINATIONS FOR QUALIFYING UNDER CATEGORIES OF NATURAL GAS," sets out procedural rules regarding category determinations under the NGPA. That section discusses jurisdictional agency authority to make category determinations, the effect of such determinations, and review of such determinations by the Commission and the courts. Section 107(c) specifically provides for determinations to be made in accordance with section 503. Section 503(a)(1)(D) mirrors this provision. On the basis of this authority, the Commission provides in this rule for use of jurisdictional agency determinations to identify qualified production enhancement gas.

[10] The final rule is intended to encourage production of natural gas from wells that require production enhancement work in order to maintain or to enhance production. Production enhancement, as we use the term, must be understood in the context of declining production rates. Production enhancement would include operations calculated to maintain the current rate of decline in production if that rate would otherwise accelerate. Enhancement operations are those intended to improve, *i.e.*, to retard, a declining production rate. A successful enhancement operation will increase the amount of gas reserves ultimately produced but need not brake completely the decline in production rate.

For all the above reasons, the Commission has decided to encourage such production enhancement work by providing an incentive price for gas subject to section 105, if such work is performed. As in the proposed rule, the incentive price provided in the final rule is the lesser of the section 109 price or the renegotiated price.

As a general matter the Commission will not at this time extend the incentive price for production enhancement gas to section 106(b) gas. We note that the Congress has provided other repricing mechanisms for such gas in section 106(c).[11] However, in order to avoid the anomalous result that would occur if the contract for production enhancement gas rolled over and resulted in a maximum lawful price lower than the incentive price available under this rule,[12] the Commission is amending its regulations in Subpart F of Part 271, concerning intrastate rollover contracts, to permit the producer to price his gas under section 106(b) at time of rollover by reference to the incentive price provided in this rule.[13]

C. How the Incentive Works

By the terms of the rule and for the reasons previously discussed, only gas sold under an existing intrastate contract or a successor contract can qualify for the incentive price. In addition, the production enhancement work to be encouraged must be commenced on or after May 29, 1980, the date the incentive price was first proposed in an open Commission meeting. We must assume that an incentive price was not necessary to induce a producer to engage in any production enhancement work commenced prior to the announcement of that price.

The producer must obtain an eligibility determination from the jurisdictional agency in order to receive the incentive price. He may obtain that determination before or after completing the production enhancement work but will be prohibited from charging and collecting the incentive price, on either an interim or a retroactive basis, until the work has been completed.

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[11] Section 106(c) authorizes the Commission to establish a maximum lawful price in excess of that prescribed in section 106 for rollover contract gas. Such a price must be just and reasonable within the meaning of the Natural Gas Act. The Commission has issued proposed rules prescribing substantive and procedural guidelines for granting "special relief" under this section (as well as sections 104(b) and 109(b)) and will coordinate the final rule on special relief with the final rule for production enhancement gas. *See* Procedures Governing Applications for Special Relief under Sections 104, 106 and 109 of the Natural Gas Policy Act of 1978, Docket No. RM79-67. Notice of Proposed Rulemaking, issued August 14, 1979, (44 FR 49466, August 23, 1979); Notice of Request for Public Comment . . ., issued January 16, 1980, (45 FR 5321, January 23, 1980); Notice of Proposed Rulemaking, issued May 9, 1980, (45 FR 31744, May 14, 1980).

[12] Under our current regulations for section 106(b), the maximum lawful price for qualified production enhancement gas in the month of rollover would be the higher of the otherwise applicable section 105 price or $1.121, as of December, 1978, adjusted for inflation to the month of rollover. It is conceivable that an escalation clause in the original contract triggered sometime after the gas qualifies under the production enhancement rule could increase the section 105 price above the incentive price, in which case no decrease in the maximum lawful price would occur when the renegotiated "successor contract" rolled over. However, for the majority of gas subject to this rule, the original contract will contain no such provision, and, absent an amendment to our rules for section 106(b), the gas will be remanded at the time of rollover to a price under the original contract terms that will, in many cases, be substantially lower than the incentive price provided under this rule. *See* discussion of price impact, *infra* in Section G.

[13] Technically, this amendment modifies our regulations for section 106(b). However, the amendment is being prescribed under our section 107 authority; it constitutes neither an intepretation of the term "expired contract" in section 106(b)(1)(A)(i) nor an exercise of our authority under section 106(c) to prescribe a higher maximum lawful price within the just and reasonable standard of the Natural Gas Act.

The Commission has crafted the eligibility requirements to insure that an incentive price is necessary for undertaking the production enhancement work and that the price itself is reasonable, and not an excessive incentive. The Commission wishes to be assured that the incentive price is available only for wells for which the section 105 maximum lawful price is insufficient to encourage application of production enhancement techniques now or in the near future, and for which the potential increase in gas production is large enough to insure that the increased cost to the pipeline purchasers and end users will not exceed the price they would have to pay for new supplies or alternative fuels. At the same time, the Commission has precluded from qualification, gas that is produced as a result of production enhancement work that would have been performed absent the availability of the incentive price or that is performed only for the purpose of repricing the gas.

As the first of its safeguards the Commission has required parties to amend the contract in existence on November 9, 1978, prior to filing an application with the jurisdictional agency. The amendment must permit collection of an incentive price stated in the application, which cannot be greater than the section 109 price.[14] This renegotiation requirement will provide the purchaser with an opportunity to resist paying the higher price if he is not reasonably assured that the production enhancement work will produce sufficient additional volumes to make the increase in cost economic.[15] Although the assumption may not be valid in all cases, the Commission also believes that most purchasers will not agree to pay a higher price unless they are sure that the additional gas would not otherwise be produced because the cost of the production enhancement work is prohibitive at the existing price. Thus the renegotiated price is a test both of the necessity for an incentive and of the reasonableness of the incentive price.

Purchasers commonly make such assessments when they negotiate contracts. We do not believe that an intrastate purchaser will accede to the intrastate producer's attempts to renegotiate the contract for flowing gas merely because the producer wishes to receive the incentive price. It is significant to note that, prior to passage of the NGPA, producers and purchasers in unregulated intrastate markets were free to renegotiate their contracts. Experience shows that many of those contracts were not renegotiated, even in circumstances where the prices under new contracts were rapidly escalating.

In addition to filing a copy of the relevant portion of the amended contract with the jurisdictional agency, the producer must also secure an oath from the purchaser that he has a reasonable basis to believe the producer's statement that the production work is necessary, that it would not be performed absent the incentive price because of the inadequacy of the section 105 price and that the reserve and production estimates are reasonable.

The Commission views this purchaser oath as essential to the integrity of the incentive pricing scheme because willingness to renegotiate a contract is not always coincident with a belief that the new price is necessary as a reasonable incentive. There may be a number of other reasons why a purchaser would be willing to pay a higher price for natural gas. Our intent in requiring the purchaser oath is to eliminate the possibility that gas will be repriced simply because of the producer's bargaining power.

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[14] If the fixed price is lower than the section 109 price, the contract price *is* the incentive price.

[15] We note that the unit cost cap establishes the upper limit on what the Commission considers economic.

In most cases purchasers are sufficiently familiar with the necessary information regarding a well's production capability and the costs or risks of enhancement work to know if a higher price is necessary for increasing gas production. If the purchaser has any hesitancy in making the statement, it is doubtful that we could determine that the incentive price sought by the applicant is necessary as a reasonable incentive under section 107.

The producer must file an oath statement that the section 105 price is inadequate, that the production enhancement work can reasonably be expected to enhance production and that the work would not be performed absent an incentive price. He must also estimate the well's current and enhanced rate of production as well as the increase in revenues to be expected from application of the incentive price and must use those estimates to determine whether the projected increase in revenues that is attributable solely to the projected increase in units of gas production exceeds a price per MMBtu equal to 200 percent of the maximum lawful price allowed for conventional, onshore development, i.e., the section 103 price.[16] We are requiring this calculation because we have determined that, if the effective cost for any increases in production appears, prospectively, to exceed the commodity value of that incremental production, the higher maximum lawful price cannot be considered a reasonable incentive, even though the higher price is necessary to induce production enhancement efforts. (However, because the unit cost cap is a function of the difference between the existing section 105 price and the incentive price, a producer who would otherwise be disqualified may be able to satisfy the cost cap requirement by lowering his renegotiated price sufficiently below the section 109 price.)

In the recently issued final rule relating to tight formation gas,[17] the Commission discussed the commodity value of natural gas and identified two benchmarks for determining that value. First, the Commission referenced the commodity value of such gas to the most recently available Btu-equivalent price for No. 2 fuel oil deliveries to electric utility facilities, which was $5.78. Based on this Btu-equivalent price, the imputed commodity value of natural gas was obtained by subtracting the average cost of transporting gas from the wellhead to the user. The average transportation and distribution costs for natural gas were determined to be approximately $1.00 per MMBtu; thus the commodity value of natural gas in relation to No. 2 fuel oil was estimated to be about $4.78 per MMBtu. The Commission also noted that, as an alternative, the commodity value of natural gas could be established by reference to the price of imported Canadian or Mexican natural gas. The Commission determined that 200 percent of the section 103 price closely approximates the price of such imported gas.[18]

Based on the same reasoning, the Commission has decided to set the unit cost cap for incremental production at a price per MMBtu equal to 200 percent of the section 103 price. This cap does not represent the actual value of the incremental production. It merely establishes a ceiling above which any incentive price for incremental production can no longer be considered reasonable.

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[16] The proposed rule would have set the unit cost cap at the price for imported crude oil. The Commission received a wide variety of comments concerning the proposed cap on the unit cost of incremental production. Many commenters supported this proposal by arguing that the cap would prevent economic waste, producer windfalls and unnecessary consumer costs. (These commenters endorsed the unit cost cap as support for their argument that the incentive price ceiling should be set higher than the section 109 price.) On the other hand, at least one commenter argued that the unit cost cap is shortsighted and should be deleted. This commenter stated that, even if the price of incremental volumes rises above the cost of foreign crude from time to time, the goal of displacing more expensive foreign oil over the long term is still advanced. According to the same argument we could allow the price of the incremental volumes to rise to a price many times that of foreign crude. We believe it appropriate, within the mandate of section 107, to establish a unit cost cap that allows as much foreign crude to be displaced as is possible while limiting the price of the gas to a level that is reasonable in the context of the NGPA.

[17] Docket No. RM79-76, issued August 15, 1980, (45 FR 56034, August 22, 1980).

[18] The price for imported Canadian or Mexican natural gas was $4.47 as of November 1980. Two hundred percent of the section 103 price was $4.858 as of November 1980.

We have permitted a calculation based on a series of estimates, and have not required completion of the production enhancement work prior to application, in order to accelerate the qualification process while allowing the applicant to be certain that he may continue to qualify for the incentive price even if a project falls short of production estimates that were reasonable when filed. We acknowledge that obtaining accurate estimates may be a problem. Nevertheless, we have decided to rely on the good faith of the parties in this regard. Should experience demonstrate that our reliance has been misplaced, the Commission will feel compelled to terminate the program.[19]

In order for a producer to qualify for the incentive price the jurisdictional agency must determine that there is a reasonable basis to conclude that the particular production enhancement work is necessary and that it can be expected to maintain or enhance production. We are relying on the jurisdictional agencies' knowledge regarding the production characteristics of the wells or zones in question and their technical expertise regarding the purpose and efficacy of the production enhancement techniques in enhancing production from those wells.

The jurisdictional agency must also examine the producer's production estimates in light of other information in the record in order to assure itself that those estimates are reasonable and that the effective cost of the incentive price does not exceed the price for new gas supplies or alternative fuels.

The Commission is comfortable at this time with its choice of an incentive price no higher than the section 109 price. Therefore, as a general matter, it is willing to accept the parties' judgments and oaths regarding the necessity for such an incentive in particular situations. The Commission will not, and the jurisdictional agency need not, inquire further concerning price, unless information or discrepancies in the record give cause for doubt as to the veracity of the producer's or purchaser's oaths.

D. Jurisdictional Agency Findings and Discretion

As a practical matter, the success of this rule in effecting the purpose for which it is intended rests with the jurisdictional agencies. We have provided latitude to the jurisdictional agencies in order to permit them to exercise their judgment in determining whether the incentive price is necessary as a reasonable incentive for the producer to undertake production enhancement work.

As we have indicated, what constitutes a reasonable incentive for production enhancement work, within the meaning of section 107, depends on several variables: the applicable contract terms upon which the section 105 price is based, the increment in production to be expected from application of the production enhancement technique, and the cost or risk associated with use of that technique. The flexibility we have afforded the jurisdictional agencies reflects our belief that in the face of so many variables, a reliable basis for affirming the necessity and reasonableness of an incentive price cannot be established by rigid regulatory guidelines.

For example, we intend that this flexibility permit a jurisdictional agency to find that no incentive price is necessary for gas produced from a horizon above other producing horizons, if it determines that the producer would have produced the upper horizon anyway in the normal course of production. It might make a similar finding if a downhole pump were installed to lift liquid hydrocarbons, *e.g.*, condensate, in order to increase gas production but the value of the condensate would, by itself, provide an incentive to installation of lift equipment. Similarly, if production enhancement work were performed on an oil well, ostensibly to increase production of associated gas, the gas might be denied the incentive price provided under this rule if the work would have been performed in any event to increase oil production.

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[19] Moreover, the Commission may find an adequate basis in specific instances to reopen a favorable determination under § 275.205 and vacate the determination if information is disclosed which indicates that the estimates were not filed in good faith.

A jurisdictional agency might also make a negative determination if it found that the filed estimates concerning incremental production were disproportionate to previously recorded production; or that the work performed was not within a defined category of production enhancement work; or that the stated or estimated cost of the production enhancement work is sufficently low in relation to the section 105 price that it could not accept the producer's oath statement that the work would not have been performed in the absence of the incentive price.

E. The Production Enhancement Techniques

The production enhancement techniques specifically included in the final rule have been broadly defined in order to permit the jurisdictional agencies to be flexible in determining what types of projects should qualify under the final rule. Any attempt on our part to define these projects more narrowly could result in the exclusion of many deserving projects. In allowing this degree of flexibility we are relying on the technical expertise of the jurisdictional agencies.

The proposed rule included, and requested comment on, five categories of production enhancement techniques. All have been included in the final rule. In addition, and in response to comments, we have added five other categories of production enhancement techniques. Should techniques that we have not considered in this rulemaking be brought to the attention of the Commission, the rule may be amended.[20]

The first category of production enhancement work is re-entry into a well that has been plugged and abandoned.

The second category covers work performed in re-entering a well to drill deeper, or to sidetrack, to a different completion location. This category will usually apply whenever a well that was drilled in the past, and from which the drilling equipment has been removed, is re-entered for further drilling.

The third category is recompletion by reperforation of a zone from which natural gas has been produced or by perforation of a different zone.[21] This category will apply whenever a well is perforated other than in the original completion location. The Commission is aware that a producer may perforate a new zone higher up the wellbore than the zone he is currently producing and then produce from both zones. Accordingly, if a well qualifies under this rule as a result of a "perforation of a different zone," only the gas produced from the new completion location will receive the incentive price. The producer will be responsible for separately identifying the gas from each completion location. We realize that, in most cases, the gas from separate completion locations will be produced through separate "stringers" and metered separately. However, if the gas is commonly metered, a reasonable allocation of production among the producing intervals or completions will be required.

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[20] In this regard, the Commission will entertain properly filed petitions by interested parties for amendments to include additional production enhancement techniques in the rule. *See* § 1.7 (b) and (e) of the Commission's Regulations.

[21] At least two commenters requested a clarification with respect to the second and third categories. They asked that the Commission clarify the proposed rule to provide that re-entry for deeper drilling, or sidetracking, to a *different* completion location (as opposed to a *new* completion location as provided in the proposed rule) and a recompletion by perforation of a different (as opposed to a *new*) zone would constitute production enhancement work. The Commission believes that this suggestion is consistent with the intent of the proposed rule. Accordingly, for clarification only, the words "new" in the second and third categories will be changed to read "different."

The fourth category is the repair or replacement of faulty or damaged casing, tubing or related downhole equipment. It should be emphasized that this category is intended to include major repair work only; routine maintenance, however costly, is not production enhancement work.[22]

The fifth category is fracturing, acidizing or installing compression equipment. The Commission recognizes that production enhancement work involving compression will often affect more than one well. Activities that affect several wells would constitute production enhancement work with respect to each well sufficiently affected to meet the other requirements of this rule. We also note that leasing of compression equipment will be treated in the same manner as purchasing of such equipment, and that upgrading compression or adding further stages of compression will be considered to be installation of compression equipment.

Commenters requested the inclusion of a variety of other production enhancement techniques. In response, we have included the following additional categories.

The first is installation of equipment necessary for removal of excessive water, brine, or condensate from the wellbore in order to establish, continue or increase production from the well. The category would apply, for example, if any one of a variety of pumping techniques were used to remove large volumes of water in conjunction with the production of natural gas, including use of electrically powered submersible pumps and sucker rod surface pumps or plunger lifts. Other procedures would include installation of smaller than normal tubing to increase the velocity of the gas in order to enable it to "blow" the water out of the well, or the injection of foaming agents to change the water into a foam, reducing the fluid pressure and enable the gas to "blow" the foam out of the well.

The second addition covers workover operations designed to reduce production of excessive water or brine in order to establish, continue or increase production of gas from the well. For example, the perforations that are "watered-out" can be plugged with cement, and gas can then be produced from other perforations of from new perforations.

The third addition concerns operations for disposing of water or brine, the presence of which prohibits or severely limits gas production from the well.

The fourth addition covers workover operations to control sand production in the wellbore, or to remove sand from the wellbore and downhole equipment in order to continue to produce gas from the well. This category can include the use of gravel packing and filtered tubing liners to keep the sand out of the tubing, or the pumping of an epoxy resin or other stablizer into the wellbore to consolidate the sand around the wellbore. This category can also include replacement of a gravel packer or a tubing liner or the cleaning of a wellbore and application of epoxy resin.

The last technique included in the rule is "inert" gas injection, such as nitrogen injection.[23] The nitrogen can be compressed or liquified and injected into the reservoir to displace the hydrocarbon gas. Once injected into the reservoir, the nitrogen expands, either forcing hydrocarbon gas from the reservoir or removing obstructions that prevented the flow of gas into the wellbore. The Commission realizes that this last category, like compression, will often apply to more than one well. To the extent that a producer can demonstrate that a well is sufficiently affected by the inert gas injection to meet the other requirements of the rule, that well will qualify for the incentive price.[24]

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[22] One commenter asked the Commission to consider inclusion of costly well maintenance projects as a category of production enhancement work. The scope of this rulemaking is limited to incentives for work that is included in the definition of production enhancement work. Operations that the Commission considers to be normal well maintenance have been excluded from that definition.

[23] In common industry parlance "inert" gas means that is noncombustible. Several commenters indicated that the section 109 price (or even a price as high as the section 102 price) would induce no work of this nature because of the extraordinary costs associated with the technique. The incentive price may be inadequate to encourage inert gas injection. However, we do not have an adequate basis in the comments to deal with this problem at this time. We will, therefore, leave its resolution to future proceedings.

Although many comments recommended that the jurisdictional agencies be permitted to qualify for eligibility other, unlisted techniques, few supplied any guidelines regarding the nature of this determination or the extent of jurisdictional agency discretion. The Commission wishes to avoid the complexities attendant in qualifying production enhancement techniques on a case-by-case basis. As we have stated, however, we will remain receptive to appropriate petitions for addition by amendment, made under § 1.7 of our regulations.

F. The Incentive Maximum Lawful Price

The incentive maximum lawful price will frequently be the same as the renegotiated price agreed to by the parties. However, that price cannot be greater than the section 109 price.

In order to avoid allocation problems that would arise were the incentive price applied only to the incremental volumes produced as a result of production enhancement work, the Commission has decided to apply the incentive price to all gas produced from a well on which production enhancement work has been performed.[25] Repricing all of the gas rather than only the incremental production will also provide a measure of revenue certainty to the producer. Even if his estimates concerning the expected increment in production eventually prove to be inaccurate, or if the production enhancement work effects no increase in production at all, he can still be assured of that increase in revenues which results from repricing the current production.

The section 109 price has been chosen as the ceiling for the price incentives provided under this rule because, in the Commission's judgment, it is sufficiently high to encourage a large number of potential production enhancement projects and low enough to prevent a windfall for producers. However, many commenters requested an incentive price ceiling higher than the section 109 price. Most commenters supported their recommendation by arguing that a higher ceiling would promote production of even more volumes of gas.

We cannot disagree that an increase in the incentive price will produce some increase in the amounts of gas produced in response to that price. We do disagree that the wording of section 107(b), which limits the price to one necessary to provide reasonable incentives, permits incentive pricing based wholly on a supply-maximization rationale.

If the purpose of section 107(b) were, without qualification, to induce the maximum production of natural gas, the Commission could attempt to create a price sufficiently high that, from the perspective of the producer, even the most costly, unpromising production enhancement ventures would appear economically attractive. However, in determining what constitutes a reasonable incentive the Commission must balance the needs of suppliers and consumers. On balance, a reasonable incentive for production enhancement work is one that will produce additional gas supplies without requiring the consumer to pay unnecessary prices to obtain those supplies.

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[24] The technique of gas cycling was also suggested for inclusion as a production enhancement technique. Gas cycling is a technique for increasing the recovery of natual gas liquids and condensate from the reservoir. The technique involves the re-injection into the reservoir of natural gas, stripped of its liquids; the gas may have been produced from that zone or another zone. Sufficient reservoir pressure is thereby maintained in order to prevent natural gas liquids from condensing within the reservoir wellbore. Although this process will result in an increase in production from the reservoir, the majority of this increase will usually be composed of natural gas liquids and condensate. There may even be a net drop in natural gas production due to volume losses caused by the separation process, losses from injected volumes unrecoverable in the reservoir, or losses due to use of natural gas as fuel to power the separator and injection equipment. An additional problem results if the injected gas is from another producing zone. In this case it is difficult to determine accurately what volume of gas produced from the target reservoir is "native" to that reservoir. For these reasons, this technique will not be included as qualified production enhancement work.

[25] But note the exception in § 271.704(c)(1)(i)(B) for gas from a well producing from more than one zone.

In the Notice of Proposed Rulemaking the Commission solicited data regarding projected increases in production that could be expected in response to different incentive prices. Unfortunately, the Commission has received no information that would permit it to quantify the potential supply responses to various hypothetical incentive prices.[26] Absent such information, the Commission is reluctant to increase the incentive price ceiling above the section 109 price.

We have looked to the statutory pricing scheme of the NGPA in order to determine what constitutes a reasonable incentive for purposes of section 107. Under Title I of the NGPA, the section 109 maximum lawful price is applicable, inter alia, to natural gas that was not committed or dedicated to interstate commerce on November 8, 1978, and that was not subject to any contract on November 8, 1978.[27] We view this as evidence that Congress considered the section 109 price to be an appropriate incentive to the production of any gas for which the price has not been established either under the Natural Gas Act or, if intrastate, by agreement of the purchaser and seller. The purchaser's inability to renegotiate a contract price now that he is subject to the restrictions imposed by section 105(b)(1) is tantamount to there being no contractually-established price to serve as a reference in pricing gas produced as the result of production enhancement efforts. The situations addressed under this rule and under section 109 are analogous. The section 109 price appears to be an appropriate incentive price ceiling for purposes of this rule.

At the very least, the Commission can be assured that such a ceiling is not unreasonable when evaluated in the context of other Title I prices. Given the minimal amount of information that is available on the potential supply and price impacts of this rule, we are inclined to proceed on this rationale. Our choice of this incentive price ceiling does not preclude us from examining the actual response to that ceiling and from determining whether it continues to be appropriate.

G. The Potential Economic Impact of the Rule

In deciding whether to permit producers and purchasers of section 105 gas to renegotiate their existing contract prices in return for undertaking production enhancement efforts, the Commission has attempted to assess the economic impact of this rule in a number of important areas. First among these are the increased revenues to intrastate producers and the associated increased cost to intrastate consumers that will be generated by the incentive price. A second concern involves the potential impact of this rule on stimulation of additional supplies of natural gas. Finally, there is the question of the rule's distributional impact on the interstate and intrastate consumer markets.

The comments received by the Commission in this proceeding make it clear that the potential impact of this rule on consumer costs may be considerable. According to information provided by the Texas Independent Royalty Owners, in Texas nearly half the gas flowing in intrastate commerce sold for less than $1.00 per MMBtu during the fiscal year ending August 31, 1979. Assuming that the situation in Texas is fairly typical of that in other producing states, this statistic suggests that, of the more than 10 trillion feet of natural gas currently flowing in intrastate commerce, as much as 5 trillion feet could be eligible for a price increase somewhere in the range of $1.40 per MMBtu.[28] Therefore, in the unlikely event that all intrastate contracts now priced below $1.00 per MMBtu were renegotiated up to the section 109 price, a gross increase of as much as 7 billion dollars could be effected in the annual payments made for gas subject to intrastate contracts. Additional costs would be imposed on intrastate consumers to the extent that contracts for intrastate gas currently selling above $1.00 per MMBtu were also renegotiated up to the section 109 price.

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[26] A few commenters labeled such projections as "inherently unquantifiable."

[27] Section 109(a)(3).

Although the potential price impact of this rulemaking is very considerable, the Commission believes that the safeguards against abuse that have been included in the rule will minimize any unwarranted results. The rule permits a purchaser to avoid paying the higher price by refusing to renegotiate in the event he determines that it would not be in his economic interest to pay a higher price in order to encourage production enhancement work.

An example of the value of low-priced gas to an intrastate consumer may be of illustrative value. An electric utility or industrial user presently taking gas at the rate of 3,000 MMBtu's per day at a cost of $.30 per MMBtu would pay 1.75 million dollars per year in additional costs if the price were renegotiated up to $1.90 per MMBtu. Clearly, such a cost increase is of sufficient magnitude that the purchaser will not voluntarily submit to such higher prices unless the potential for increased supply appears substantial.

Alternatively, real costs may be imposed upon intrastate customers if they are precluded from contract renegotiations keyed to enhanced production activity. A purchaser of gas subject to a contract price may be unable to compel the producer to undertake costly production enhancement measures. Purchasers, in their discussions with producers, are in the best position to judge whether a price higher than the otherwise applicable section 105 price may be discouraging cost effective production stimulation efforts by the producer. The Commission is willing to allow purchasers to amend the price protections afforded them by section 105 where such renegotiation is in the purchaser's perceived self-interest.

The Commission's initiation of this rulemaking stems from its perception that the potential supply response to production enhancement initiatives is substantial. Despite the many differences that exist among natural gas production projects, all producing wells reach a stage in their production life where the cost of maintaining production exceeds the revenue stream from that well. If the price of natural gas is restrained below market levels, the point in the well's production life at which a producer will be unable to recover his out-of-pocket expenses will occur earlier than it would if the gas were sold at prices closer to its market value. The economic life of many wells currently producing intrastate gas could be extended, in appropriate circumstances, if existing contract prices were permitted to increase.

The volume of additional supplies that will be elicited through production enhancement incentives provided in this rule cannot be estimated with any absolute certainty. The rule imposes no specific volumetric standard on the producer. Rather, the required oath statement and unit cost cap are designed to give guidance to both the seller and buyer on the presumed value of incremental gas supplies under current market circumstances. These provisions should insure the maximum economically practicable supply response to expenditures associated with production enhancement.

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[28] The $1.40 per MMBtu figure represents the difference between an assumed $0.50 per MMBtu price for gas priced below $1.00 per MMBtu and a maximum lawful price under section 109 of approximately $1.90 per MMBtu.

Finally, the Commission recognizes the possibility that the rule may make gas presently sold under intrastate contracts less accessible to interstate purchasers if the current purchaser seeks to obtain an extended supply commitment in return for consenting to the higher prices authorized by this rule. However, to the extent this rule elicits gas that would not otherwise be purchased, interstate market interests would be unaffected. Most gas subject to renegotiation is produced from wells that are at or near the end of their presently useful producing life. Thus, the Commission expects the rule's distributional impact on the interstate and intrastate markets to be relatively modest.

II. Summary of the Final Rule

A. Definition of Qualified Production Enhancement Gas

We have added to Subpart G of Part 271 of our regulations a new section, § 271.704, which defines "qualified production enhancement gas" and establishes a maximum lawful price for such gas. Paragraph (c)(1) of § 271.704 establishes five criteria which the juridictional agencies are to apply in identifying qualified production enhancement gas.

First, the jurisdictional agency must find that the gas is produced from a well (or a zone, in the case of multiple completion locations) on which production enhancement work was commenced, or will be commenced, on or after May 29, 1980. In order to make this finding, the jurisdictional agency must determine that the work constitutes qualified production enhancement work as described in paragraph (d)[29] and that the work was commenced on or after May 29, 1980.

Second, the jurisdictional agency must find that the gas is subject to a maximum lawful price under section 105.

Third, the jurisdictional agency must find that a renegotiated price is in effect for a first sale of the gas at the time of application. A renegotiated price is defined in paragraph (b)(3) as a price (not higher than the section 109 price) which was agreed to after the enactment of the NGPA in connection with production enhancement work which is the subject of an application under this rule.

In essence, the fourth criterion in the definition requires the jurisdictional agency to find that the requisite estimates and oath statements, regarding the necessity for and reasonableness of the incentive, are not contradicted by other information in the record.

Finally, the jurisdictional agency must find that the price for the increased production does not appear, prospectively, to exceed the commodity value of that incremental production. Clause (v) of paragraph (c)(1) sets forth the formula for making this calculation. The results must indicate that the projected increase in revenue, attributable solely to the projected increase in units of gas production, may not exceed a price per MMBtu equal to 200 percent of the maximum lawful price allowed for conventional, onshore development (i.e., the section 103 maximum lawful price) for the month in which the application is made.

The calculation will be based on production estimates filed with the application. The applicant must first estimate the total number of MMBtu's that would be produced from the well in the absence of production enhancement work over a five-year test period commencing with the month the application is made.[30] In doing so, the applicant must consider, at the time of application, the condition of the well and the rate of production absent production enhancement work and must then estimate total production for the next five years. The applicant must then estimate the total number of MMBtu's that would be produced from the well over the same five-year period, based on the assumption that the production enhancement work was completed on the date of application.[31] Once these estimates have been made, the "projected increase in units of production" can be calculated by subtracting the first estimate from the second.

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[29] *See* discussion of production enhancement techniques beginning in Part I, Section E, *supra*.

[30] These estimates are based only on production of gas; oil, LNG or other liquid hydrocarbons are not to be included in the calculation.

In order to calculate the "projected increase in revenue," the applicant must multiply the number of MMBtu's that would be produced absent production enhancement work by the otherwise applicable maximum lawful price under section 105 as of the date of application. The applicant must then multiply the total number of MMBtu's that will be produced from the well after production enhancement work is completed by the section 109 price at the time of application. However, if the renegotiated price is less than the section 109 price and if it is also either a fixed price or a percentage of the section 109 price, the applicant may base the calculation on the renegotiated price rather than the section 109 price. The projected increase in revenue to be derived under the rule is determined by subtracting the first product from the second product.

Finally, the applicant must divide the projected increase in revenue by the projected increase in units of production in order to determine whether the price per MMBtu for the incremental production exceeds 200 percent of the section 103 price as of the month the application is filed.

If the jurisdictional agency makes all five findings, the natural gas will qualify as production enhancement gas. If the gas receives this determination, it is subject to the maximum lawful price specified in paragraph (a) of § 271.704.

B. The Incentive Price

The incentive price set forth in § 271.704(a) is the lesser of the section 109 maximum lawful price or the renegotiated price.

The final rule adopts the requirement in the proposal that a newly negotiated price be in effect at the time the producer files for a determination. (However, the definition of that price is changed so that it simply requires renegotiation after November 9, 1978, in connection with the production enhancement work.) The determination is keyed to the particular renegotiated price,[32] evidence of which must be included in the application. Therefore, if the contract is subsequently amended to modify that price a new application and a new jurisdictional agency determination will be required.

Under the filing requirements in § 274.205(f) the producer must submit that portion of the sales contract which authorizes collection of the incentive price established in § 271.704. In most instances parties to the contract will have to amend their contract before filing an application with the jurisdictional agency. In such cases the filing will consist of the contract amendment drafted in response to the availability of the incentive price under this rule.

Section 271.704(a)(3) provides that the increase in the price paid for the natural gas by reason of this rule will not result in the elimination of price controls under section 121(a)(3) of the NGPA. The Commission does not believe that Congress intended it to deregulate natural gas subject to section 105 which, but for the effect of the final rule, would not be sold for a price in excess of $1 on December 31, 1984. Elimination of price controls under that section will occur only if, and when, such elimination would have occurred based on the maximum lawful price that would have been applicable but for this rule.

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[31] These estimates may be made, and an eligibility determination received, before production enhancement work is commenced on the well. *See* discussion of Collection of the Incentive Price, *infra*, Section D.

[32] We note that this may be a single price or a set of fixed prices such as a price equivalent to a certain percentage of the section 109 price.

Because the definition of qualified production enhancement gas requires that the gas be subject to a maximum lawful price prescribed by Subpart E of Part 271, i.e., the section 105 price, once the contract under which it is sold rolls over, the gas is outside the scope of § 271.704. In order to permit a producer to continue to collect an incentive price for gas that previously qualified under § 271.704, we have amended our regulations regarding the maximum lawful price for gas subject to section 106(b). For purposes of determining the maximum lawful for such gas under § 271.602 of our regulations, the maximum lawful price paid under the expired contract, in the month in which the rollover contract becomes effective, will be deemed to include any amount paid by reason of qualification under the final rule in § 271.704.

C. Filing Requirements

The filing requirements are provided in new paragraph (f) of § 274.205. The applicant must file an FERC Form No. 121; a detailed statement describing the production enhancement work; an itemized statement of the costs incurred or to be incurred in performing the work (and invoices, where appropriate); the unit cost cap calculation and related production estimates; that portion of the contract which authorizes collection of the incentive price; and, if the jurisdictional agency requires, certified copies of records upon which the applicant has relied.

In addition, the applicant must include separate oath statements by himself and the purchaser. The applicant must file a statement, under oath, that the production enhancement work is necessary, and can be reasonably expected, to enhance production; that the section 105 maximum lawful price does not provide an adequate incentive for the performance of the production enhancement work; and that, but for the availability of a price at least as high as the renegotiated price, the production enhancement work would not have been or will not be performed.

The applicant must also state that the production enhancement work was not commenced before May 29, 1980; that to the best of his knowledge and belief, the production estimates that are included in the application are reasonable; and that he has no knowledge of any information inconsistent with the filed statements and estimates.

The purchaser must state under oath that, to the best of his knowledge and belief, there is a reasonable basis for the statements and estimates made by the applicant. The purchaser must also state that he has no knowledge of information not described in the application that is inconsistent with the statements made by the applicant.

D. Collection of the Incentive Price

A producer may choose to perform production enhancement work on a well before filing an application for an eligibility determination. Under §§ 273.202 and 273.203, such a producer may make interim collections of the incentive price for all deliveries of gas made after the date the application is filed with the jurisdictional agency. In addition, we have amended § 273.204(a)(1) to permit collection of the incentive price retroactive to the date that the qualifying production enhancement work was completed.

On the other hand, if the producer so chooses, he may apply for and receive an eligibility determination before completing, or even commencing, the production enhancement work. Under such circumstances, § 271.704(a)(2) prevents the producer from charging the incentive price, on either an interim or a retroactive basis, before the production enhancement work upon which the application is based has been completed and the producer has given written notice to the purchaser stating that the production enhancement work has been completed.

III. Environmental Impact

The Commission staff has completed an environmental assessment of this rule and has concluded that establishing an incentive price would not constitute a major federal action significantly affecting the quality of the human environment. An environmental impact statement is not required.

In the environmental assessment, the staff identified a potential for impact of fracturing operations on fresh water aquifers. In order to determine whether further limitations to qualification are necessary in order to protect such fresh water aquifers, we will monitor environmental data that we will require from applicants regarding fracturing operations. However, we emphasize that, as the rule is currently written, the five criteria for qualification do not include any environmental standards and that information on the potential environmental impact of a project will not be used to disqualify a well for the incentive price.

If an application is based to any extent on the performance of fracturing operations, the applicant will be required to file specified information regarding the environmental effects of the fracturing operations. However, the jurisdictional agency may waive this filing requirement if it determines that there exists in the state an adequate program reasonably designed to assure no damage to fresh water aquifers.

We will review any filed environmental information at the time that the jurisdictional agency forwards the notice of determination to us. We do not intend to use the information to disqualify a particular well after the production enhancement work has been performed on it. We will use this information, however, in order to determine the necessity of amending the rule.

IV. Public Procedures and Effective Date

These regulations were originally proposed for comment on July 25, 1980, in Docket No. RM80-50 (45 FR 51219, August 1, 1980). For 30 days thereafter comments were received, and on August 26, 1980 and September 4, 1980, two public hearings were held on these regulations. By this process the Commission has complied with 5 U.S.C § 553 and with section 502(b) of the NGPA, which requires that, "[t]o the maximum extent practicable," an opportunity for the oral presentation of data, views and arguments be afforded for certain regulations under the NGPA. The regulations contained in this order rest upon consideration given to the information received during the above-described notice, comment, and hearing process. The Commission finds that further notice and public procedure with respect to these regulations are unnecessary.

Sections 271.802(c), 271.701(b), 271.704, 273.204(a)(1)(iii) and 274.205(f) are being issued as final regulations effective December 15, 1980.

(Department of Energy Organization Act, 42 U.S.C §§ 7107-7352; E.O. 13009, 42 Fed. Reg. 46267; Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3422)

In consideration of the foregoing, Subparts F and G of Part 271, Subpart B of Part 273, and Subpart B of Part 274, Subchapter H, Chapter I, Title 18 of the Code of Federal Regulations are amended as set forth below, effective December 15, 1980.

By the Commission. Commissioner Sheldon concurring.

Kenneth F. Plumb,
Secretary.

[¶ 30,211]

45 F. R. 79024 (November 28, 1980)

18 CFR Part 375

[Docket No. RM81-5; Order No. 112]

Rule Revision Subdelegation Authority

November 21, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission revises its rules of practice and procedure to permit an official to whom the Commission has delegated certain functions under Part 375 to subdelegate the authority to carry out those functions to the deputy of such official, to the head of a division, or a comparable official.

EFFECTIVE DATE: November 21, 1980.

FOR FURTHER INFORMATION CONTACT:
Christine R. Benagh, Staff Attorney, Regulatory Development, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8062.

The Federal Energy Regulatory Commission (Commission) hereby revises its rules of practice and procedure relating to delegations, to permit subdelegations of authority previously delegated to certain officials by the Commission.

I. Background and Discussion

The Commission, in the past, has delegated to specific Commission officials certain of its ministerial regulatory functions, which appear in Part 375, Subpart C, of the Commission's rules and regulations. The officials who carry out these delegated functions include the Secretary of the Commission, the Chief Accountant, the Director of the Office of Pipeline and Producer Regulation, the Director of the Office of Electric Power Regulation, and the Solicitor. Before the revision promulgated herein, these officials could subdelegate these functions only in the event of their absence. The Commission believes that permitting subdelegation only when such officials are absent may hinder efficient administration of its duties and responsibilities.

Therefore, the rules of the Commission are being revised, in the interest of efficient administration, to delete the limitations which permit a subdelegation only when the delegatee of the Commission is absent. The subpart on delegations is also being amended to clarify to which officials a subdelegation may be made: the deputy of the Commission's delegatee, the head of a division, or a comparable official.

In consideration of the foregoing, the Commission is revising its rules to permit subdelegations, under Part 375, Subpart C of its rules of practice and procedure, to certain classes of Commission officials even when the Commission's delegatee is not absent.

II. Public Procedures and Effective Date

Since this rule concerns a matter of agency practice and procedure, notice and public comment thereon is unnecessary pursuant to 5 U.S.C. 553(b). The Commission believes that the delegated functions, which appear in Part 375, Subpart C, of the Commission's regulations, will be administered more easily and more efficiently if this rule is made effective as soon as possible. Therefore, the Commission finds that good cause exists pursuant to 5 U.S.C. 553(d)(3) to make this rule effective immediately.

(Department of Energy Organization Act, (42 U.S.C. 7107 *et seq.*; Federal Power Act, (16 U.S.C.), 791-828c), as amended; Natural Gas Act, (15 U.S.C. 717-717w), as amended; Natural Gas Policy Act of 1978, (15 U.S.C. 3301 *et seq.*); Public Utilities Regulatory Policies Act of 1978, (16 U.S.C. 2601 *et seq.*); Exec. Order No. 12009, 3 CFR 142 (1978))

In consideration of the foregoing, the Commission amends Subpart C, Part 375, Subchapter W, Chapter I, Title 18 of the Code of Federal Regulations as set forth below, effective November 21, 1980.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,212]

45 F. R. 80273 (December 4, 1980)

18 CFR Part 271

[Docket No. RM81-6]

Maximum Lawful Price for Natural Gas From Stripper Wells

November 25, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Interim rule.

SUMMARY: The interim rule would allow a stripper well operator whose well exceeds the 60 Mcf per production day limitation to file an application for

"recognized enhanced recovery technique" status more than 30 days after notice of disqualification has been filed. Currently, an enhanced recovery application must be filed within 30 days or stripper well status is lost. The amendment would allow continued collection of stripper well rates, subject to refund, only if the application is filed within the 30-day limit. In all other cases the price permitted by section 108 could be collected, subject to refund, only from the date of filing of an application for "recognized enhanced recovery." In addition, § 271.805(c) is amended to make paragraph (c) consistent with paragraph (a).

DATES: Effective date: November 25, 1980. Comments on the interim rule are due on January 23, 1981. Written requests for a public hearing are due on December 17, 1980.

ADDRESSES: Comments or requests for hearing must be filed with the Office of the Secretary, 825 North Capitol St. NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Randall S. Rich, (202) 357–8511 or Susan Tomasky, (202) 357–8461.

I. Introduction

In Subpart H of its regulations, the Federal Energy Regulatory Commission (Commission) has established rules implementing section 108 of the Natural Gas Policy Act of 1978 (NGPA), which set a maximum lawful price for natural gas from stripper wells. The NGPA defines a stripper well as one that produces no more than 60 Mcf of non-associated natural gas per day in the 90-day production period preceding the date of application. However, it permits a well previously determined to be a stripper well, that exceeds the 60 Mcf per day production rate, to continue to qualify if the well operator demonstrates that the increased production is the result of "recognized enhanced recovery techniques." The Commission is adopting an interim rule amending § 271.805 of its regulations concerning stripper well disqualification and "recognized enhanced recovery techniques."

II. Discussion

Section 108 of the NGPA provides that in order for a well to qualify as a stripper well it must produce 60 Mcf or less of nonassociated natural gas per production day during the qualifying 90-day production period. However, a well that has previously qualified as a stripper well, but subsequently exceeds the 60 Mcf limit may continue to qualify for the stripper well price if the increased production is shown to be the result of the application of "recognized enhanced recovery techniques." *See* section 108(b)(2).

Section 271.805(a) of the Commission's regulations implementing section 108 requires that the operator and purchaser give notice to the Commission and the appropriate jurisdictional agency when a stripper well exceeds the 60 Mcf limit. However, under § 271.805(b), the operator of such a well may continue to collect the stripper well price, if, within 30 days after notice is given, it files a petition with the jurisdictional agency for a determination that the increased production is the result of a "recognized enhanced recovery technique." Absent such a filing, the well ceases to be eligible for the section 108 price.

The Commission's intent in adopting the rule under § 271.805(b) was to permit a producer to continue collection of the stripper well price if the well in question exceeded the 60 Mcf limit as a result of the application of a "recognized enhanced recovery technique."

We continue to believe that this purpose is appropriate. However, the rule as presently stated does not address the circumstance of a producer that files a "recognized enhanced recovery technique" petition after the end of the 30 day period. Because the 30 day filing requirement is a condition to continued qualification for the section 108 price, the rule may be construed so as to permanently deprive an operator of the section 108 incentive price due solely to failure to make a timely filing.

This results because applying a "recognized enhanced recovery technique" may increase a stripper well's production beyond the 60 Mcf per day limit. If there is no notice to the Commission and the jurisdictional agency of the cause of the increase, stripper well status will be lost. Currently, the regulations contain no provision which would permit a well to qualify again unless production somehow drops below the limit.

We do not believe that such a result is required by the statute, nor is it necessary to effect the purpose of the 30 day filing requirement. Therefore, the Commission is adopting amendments to § 271.805 to provide that the failure to file within the prescribed 30 day period results in disqualification from section 108 eligibility only until such time as the operator complies with the filing requirement.

The Commission believes that the rationale underlying these amendments regarding the timely filing of recognized enhanced recovery technique petitions also applies to petitions to declare wells to be "seasonally affected" and motions by producers opposing purchaser notice of excessive production. We have therefore amended § 271.805(b) to effect this belief.

In addition, the Commission takes this opportunity to amend § 271.805(c) to reflect the effect of a notice of disqualification filed by either the operator or the purchaser, pursuant to § 271.805(a). This change makes § 271.805(c) consistent with the language in paragraph (a).

III. Summary of Regulation

Accordingly, § 271.805(b) is being amended to eliminate the 30-day filing requirement for petitions for recognized enhanced recovery techniques, seasonally affected wells and motions opposing excess production notices. This amendment will permit the filing of such petitions at any time.

Section 271.805(c) is being amended, consistent with § 271.805(a), to reflect the effect if a notice of disqualification filed by either the operator or the purchaser of excess production. Section 271.805(d) is being added to provide that collections of the stripper well price subsequent to the filing of a notice of excess production may continue only if a "recognized enhanced recovery technique" petition, a "seasonally affected well" petition or a motion opposing purchaser notice is filed within 30 days after the notice is filed. If a petition is filed after the 30 day period, collection subject to refund may commence on the day such filing is made.

IV. Effective Date

This interim rule relieves restrictions previously placed on applicants under the Commission's regulations. Accordingly, it is being made effective immediately for all determinations which have not become final as of the day before the date of issuance of this order. This rule shall not become final, however, until the Commission has had an opportunity to receive oral and written presentation of relevant data, views and arguments.

V. Public Procedure

A. Written Comments

Interested persons are invited to submit comments, data, views, or arguments with respect to this interim regulation. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should refer to Docket No. RM81-6. An original and 14 copies should be filed. All comments received prior to 4:30 p.m. January 23, 1981, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the public file that has been established in this docket. This file is available for public inspection in the Commission's Division of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C., during regular business hours.

B. Public Hearing

Interested persons may request the opportunity for an oral presentation of their views at a public hearing. Requests for a hearing should be submitted no later than December 17, 1980, to the Office of the Secretary, Federal Energy

Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C., 20426, and should reference Docket No. RM81-6. If a public hearing is held in this docket, the time and place will be announced by December 22, 1980.

(Natural Gas Policy Act of 1978, (15 U.S.C. 3301-3432); Department of Energy Organization Act, (42 U.S.C. 7101, *et seq.*); E.O. 12009, 42 FR 46267)

In consideration of the foregoing, the Commission amends Subpart H, Chapter I, Title 18, Code of Federal Regulations, on an interim basis, as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,213]

45 F. R. 80817 (December 8, 1980)

18 CFR Part 282

[Order No. 113; Docket No. RM80-46]

Rule Adopting Revised Alternative Fuel Price Ceilings for the Month of April 1980; Final Rule

December 1, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) adopts as a final rule an interim rule issued on March 28, 1980 (45 FR 22891, April 4, 1980), revising the incremental pricing alternative fuel price ceilings for the month of April 1980. The final rule amends § 282.204(a) of the Commission's regulations to provide that alternative fuel price ceilings for the month of April 1980 are the ceilings set forth in § 282.204(a), rather than the ceilings published on March 20, 1980, by the Energy Information Administration (EIA) of the Department of Energy. The ceilings published on March 20, 1980, by the EIA did not accurately reflect actual fuel oil prices. The revised ceilings as set forth in the final rule correct the inaccuracy.

DATE: Final rule effective December 31, 1980.

FOR FURTHER INFORMATION CONTACT:

Ronald Leach, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Room 4308A, Washington, D.C. 20426 (202) 357-8133

Barbara Christin, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Room 8602A, Washington, D.C. 20426 (202) 357-5555

SUPPLEMENTARY INFORMATION:

I. Introduction

The Federal Energy Regulatory Commission (Commission) is adopting, as a final rule, an interim rule that amended its incremental pricing regulations (18 CFR Part 282) under the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3301-3432). The interim rule (Docket No. RM 80-46, issued March 28, 1980, 45 FR 22891, April 4, 1980) amended § 282.204(a) to provide that alternative fuel price ceilings for the month of April 1980 are the ceilings set forth in § 282.404(a), rather than the ceilings published on March 20, 1980, by the Energy Information Administration (EIA) of the Department of Energy. The ceilings published on March 20, 1980, by the EIA did not accurately reflect actual fuel oil prices. The interim amendment corrected the inaccuracy.

II. Background

Title II of the NGPA requires the Commission to prescribe and make effective a program of incremental pricing of natural gas used as industrial boiler fuel. Section 204(e) of the NGPA directs the Commission to establish ceilings on prices charged to incrementally priced users, based on the cost of alternative fuel oils in each region designated by the Commission.

Under the Commission's incremental pricing regulations, ceiling prices for each month are based on the observed price of high-sulfur No. 6 fuel oil in each of the 48 contiguous states. These ceiling prices are published in the Federal Register on, or before, the twentieth day of the month preceding their effective date. The collection of data, the calculation of the price ceilings, and the publication of these ceilings is performed by the EIA, in accordance with its statutory responsibilities. (Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.;* Department of Energy Delegation Order No. 0204-3, October 1, 1977).

Pursuant to § 282.404(a) of the Commission's regulations, on March 20, 1980, the EIA published the alternative fuel price ceilings for the month of April (45 FR 18109). Those April prices represented a significant increase over the March prices. Shortly after the ceiling prices were published, the EIA, several pipelines, and other persons notified the Commission that, in some states, the No. 6 fuel oil prices observed for April were significantly lower than the published alternative fuel price ceilings.

The Commission recognized that the normal disparity in some states or regions between the alternative fuel prices published by the EIA and the observed prices had been aggravated by the application of a computational method employed by the EIA that was designed to minimize month-to-month variations in the published alternative fuel price ceilings. Therefore, the Commission requested the EIA to recalculate the alternative fuel price ceilings for the month of April 1980, using a method more responsive to variations in current prices. The recalculated ceilings were significantly lower in a number of states than the previously published April price ceilings.

Accordingly, the Commission issued an interim rule on March 28, 1980, which revised the alternative fuel price ceilings for April 1980, thereby superseding the ceilings published by the EIA on March 20, 1980. In the interim rule, the Commission, in accordance with 5 U.S.C. 553(b) found good cause to waive the normal notice and comment procedures and the rule took effect immediately. On April 14, 1980, a public hearing was held in Washington, D.C. for the presentation of oral comments on the interim rule. Written comments on the interim rule were filed by, among others, pipelines, local distribution companies, and end-users of natural gas.

In addition, a timely petition for rehearing of the interim rule was filed by the Public Service Company of North Carolina, Inc. and North Carolina Natural Gas Corporation (Petitioners).[1]

On May 5, 1980, the Commission issued an Order Granting Rehearing Solely for Purposes of Further Consideration. In that order, the Commission announced that it would consider the arguments raised in the application for rehearing in the course of reviewing comments on the interim rule and issuing final regulations. The issue raised in the petition for rehearing is discussed below.

III. Application for Rehearing

In their joint Petition for Rehearing, Petitioners requested a downward adjustment of the $3.45 per MMBtu alternative fuel price ceiling set forth in the interim rule for the State of North Carolina, because the $3.45 ceiling reflected no adjustment from the figure published by the EIA on March 20, 1980.

The interim rule provided that a state's alternative fuel price ceiling for the month of April was to be the *lower* of: (1) The price ceiling published on March 20th by the EIA; or (2) the revised price ceiling calculated by the EIA. In the case of North Carolina, the recalculated price ceiling was $3.45, the same as the figure published on March 20th. Therefore, no adjustment was necessary, and the March 20th figure of $3.45 remained the alternative fuel price ceiling for North Carolina. Accordingly, the Commission denies Petitioners' request.

[The next page is 31,425-3.]

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[1] The joint application was in the form of an Application for Rehearing, Petition for Immediate Relief, and Comments.

IV. Discussion of Comments

All of the commenters supported the Commission's prompt issuance of the revised alternative fuel price ceilings.

In addition, a number of commenters suggested that the Commission investigate the methodology used by the EIA to establish alternative fuel price ceilings, pointing to the continuing discrepancies between the price ceilings published by the EIA and the observed market prices. Several commenters also proposed that the Commission adopt a "failsafe mechanism" as an alternative to the present methodology used by the EIA in calculating and publishing alternative fuel price ceilings. The failsafe mechanism would allow a non-exempt user to pay a lower incremental pricing surcharge than that based upon the EIA published price, if the user could certify that a lower price is available to that user.

On November 4, 1980, the Commission issued a Notice of Inquiry in Docket No. RM79-21 (45 FR 74505, November 10, 1980) requesting comments on, among other things, proposed revisions to the methodology used by EIA for the calculation of the alternative fuel price ceilings. The written comments and the testimony given at the public hearing in the instant docket concerning the EIA's methodology and the proposed failsafe mechanism will be incorporated into Docket No. RM79-21 and will be considered in the context of that docket.

V. Effective Date

This rule is effective as a final rule on December 31, 1980.

The Commission orders:

For the reasons set forth above the Commission orders:

(A) The petition for rehearing of the interim rule is denied; and

(B) Section 282.404(a) of Subpart I of Part 282, Chapter I, Title 18, Code of Federal Regulations is amended as set forth below, effective December 31, 1980.

(Natural Gas Policy Act of 1978, Pub. L. No. 95-621, 92 Stat. 3350, (15 U.S.C. 3301 *et seq.*))

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,214]

45 F. R. 82171 (December 15, 1980)

18 CFR Part 282

[Docket No. RM80-29]

Section 206(d) Rule Exempting Agricultural Uses From Incremental Pricing Surcharges; Effective Date

September 11, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of effective date.

SUMMARY: On May 7, 1980, the Federal Energy Regulatory Commission (Commission) issued a rule (45 FR 33601, May 20, 1980) providing an exemption for agricultural uses of natural gas from incremental pricing surcharges until such time as the Commission determines there is an economically practicable and reasonably available alternative fuel for a particular use. On the same day, the rule was transmitted to Congress for review as required by section 206(d) of the Natural Gas Policy Act of 1978. During the period for Congressional review, neither House disapproved the submittal. The exemptive rule thus became effective immediately upon expiration of the thirty-day Congressional review period.

EFFECTIVE DATE: June 12, 1980.

FOR FURTHER INFORMATION CONTACT: Alice Fernandez, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-9095.

Kenneth F. Plumb,
Secretary.

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[¶ 30,214A]

45 F. R. 82171 (December 15, 1980)

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18 CFR Part 282

[Docket No. RM79-21]

Rule Further Exempting Industrial Boiler Fuel Facilities From Incremental Pricing Above the Price of No. 6 Fuel Oil and Applying Ceiling Prices to Forty-Eight Incremental Pricing Regions; Effective Date

September 11, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of effective date.

SUMMARY: On May 7, 1980, the Federal Energy Regulatory Commission (Commission) adopted Order No. 81, a final rule subject to Congressional review, which provided that large industrial boiler fuel facilities subject to the incremental pricing program will continue to be surcharged only at the level of the high sulfur No. 6 fuel oil price through October 31, 1981, (45 FR 31300, May 13, 1980). The rule was later transmitted to Congress for review as required by section 206(d) of the Natural Gas Policy Act of 1978. During the period for Congressional review, neither House disapproved the submittal. The exemptive rule thus became effective July 1, 1980.

EFFECTIVE DATE: July 1, 1980.

FOR FURTHER INFORMATION CONTACT: Alice Fernandez, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-9095.

Kenneth F. Plumb,
Secretary

[¶ 30,215]

45 F. R. 82915 (December 17, 1980)

18 CFR Part 282

[Docket No. RM80-48; Order No. 114]

Definition of Agricultural Use; Incremental Pricing; Final Rule

December 5, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final Rule.

SUMMARY: Title II of the Natural Gas Policy Act (NGPA) requires the Federal Energy Regulatory Commission (Commission), within certain guidelines, to institute and administer an incremental pricing program. The program is designed to pass through, by surcharge, to certain industrial facilities that use natural gas as boiler fuel, a portion of the increases in the wellhead prices of natural gas allowed under Title I of the NGPA. However, industrial facilities that use natural gas as boiler fuel for an agricultural use are currently exempt from the incremental pricing program. The Commission is amending its regulations that define "agricultural use" of natural gas for purposes of an exemption from incremental pricing under Title II of the NGPA by adding eight uses of natural gas to the definition of agricultural use in § 282.202(a) of the regulations.

EFFECTIVE DATE: December 5, 1980.

FOR FURTHER INFORMATION CONTACT:

Roger B. Coven, Office of General Counsel, 825 North Capitol Street, NE., Room 4001, Washington, D.C. 20426, (202) 357-9124

Barbara Christin, Office of General Counsel, 825 North Capitol Street, NE., Room 8602B, Washington, D.C. 20426, (202) 357-5555

Definition of Agricultural Use in § 282.202(a) of the Commission's Regulations on Incremental Pricing, Docket No. RM80-48, Order No. 114, Final Rule.

December 5, 1980.

I. Introduction

The Federal Energy Regulatory Commission (Commission) is amending its regulations on incremental pricing (18 CFR Part 282) under Title II of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3301-3432). Specifically, the list of agricultural uses of natural gas set forth in § 282.202(a), which are exempt from the incremental pricing regulations, is expanded by the addition of the following: Hardboard, wood preserving, cellulosic man-made fibers, processed cotton linters, food preservative BHA, food-grade waxes (food containers), metal shipping containers (food related), and naturally occurring vitamins.

II. Background

Title II of the NGPA requires the Commission, within certain guidelines, to institute and administer an incremental pricing program. The program is designed to pass through, by surcharge, to certain industrial facilities that use natural gas as boiler fuel, a portion of the increases in the wellhead prices of natural gas allowed under Title I of the NGPA. However, industrial facilities that use natural gas as boiler fuel for an agricultural use, as defined in section 206(b) of the NGPA, are currently exempt from the incremental pricing program. Section 206(b)(3) defines "agricultural use" as follows:

> **(b)(3) AGRICULTURAL USE DEFINED.—** For purposes of this subsection, the term "agricultural use", when used with respect to natural gas, means the use of natural gas to the extent such use is—
>
> (A) for agricultural production, natural fiber production, natural fiber processing, food processing, food quality maintenance, irrigation pumping, or crop drying; or
>
> (B) as a process fuel or feedstock in the production of fertilizer, agricultural chemicals, animal feed, or food.

The definition of "agricultural use" originally proposed by the Commission to implement this exemption was limited to those uses of natural gas certified as "essential agricultural uses" by the Secretary of Agriculture pursuant to

Title IV of the NGPA.[1] After reviewing comments submitted on the proposal, the Commission expanded the definition of "agricultural use" in the final regulations to include the Standard Industrial Classification (SIC) Codes representing the processing and finishing of natural fiber by the textile industry.[2]

After the issuance of the final regulations, representatives of the wood and paper industries filed petitions for rehearing of the regulations requesting that the definition of agricultural use be further expanded to encompass wood processing. In Order No. 49–A the Commission granted the petitions for rehearing and amended its regulations to include the SIC Code representing the processing of wood.[3] Subsequently, the Commission received additional requests for inclusion of specific uses of natural gas within the definition of agricultural use in the form of petitions for rehearing of Order No. 49–A, requests for interpretations, and an application for an adjustment. In its Order Denying Rehearing of Order No. 49–A, issued in Docket No. RM79–14 on February 21, 1980 (45 FR 13,068, February 28, 1980), the Commission stated that the most efficient and appropriate method of handling these additional requests would be to consider them in a separate docket. Accordingly, on April 10, 1980, the Commission issued a Notice of Proposed Rulemaking (Notice) in this docket (45 FR 25,825, April 16, 1980). The Notice contained a description of the uses set forth in the petitions for rehearing, the requests for interpretations, and the application for adjustment,[4] and requested comment on additional uses which should be included in the definition of agricultural use.

Twelve persons filed written comments in this docket. Three of those twelve persons also presented oral statements at a public hearing held in Washington, D.C. on June 3, 1980. In addition, the Commission has considered the applications for rehearing of Order No. 49–A, and the requests for interpretations or adjustments referred to in the Notice. The uses of natural gas that the Commission has considered in this docket for inclusion in the definition of agricultural use are discussed below.

III. Summary of Comments and Revisions to Regulations

A. SIC Code 24996 Hardboard, Tempered and Untempered

In its application for rehearing of Order No. 49–A, the American Hardboard Association requested the Commission to define agricultural use to include the manufacture of hardboard (SIC Code 24996), which is a panel manufactured from wood fibers. The Commission has determined that wood is a natural fiber, and, as such, the processing of wood comes within the definition of agricultural use set forth in section 206(b) of the NGPA. (Order No. 49–A at 7.) Since the manufacture of hardboard involves the processing of wood, a natural fiber, the Commission is adding SIC Code 24996 to its definition of agricultural use.

B. SIC Code 2491 Wood Preserving

The American Wood Preservers Institute (AWPI) requested that the Commission add SIC Code 2491 to § 282.202(a), stating that wood preserving involves the processing of natural fibers (lumber, plywood, timber, poles, and ties) to increase their useful life. Since the Commission has determined that wood is a natural fiber, the processing of wood to increase its useful life is "natural fiber processing" and, as such, an agricultural use of natural gas. Therefore, SIC Code 2491 is added to § 282.202(a).[5]

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[1] *Proposed Regulations Implementing the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978*, Docket No. RM79–14, issued June 5, 1979, 44 FR 33099 (June 8, 1979).

[2] Docket No. RM79–14, Order No. 49, issued September 28, 1979, 44 FR 57726 (October 5, 1979). See also Interim Rule, Docket No. RM80–75, issued October 8, 1980, 45 FR 67276 (October 9, 1980).

[3] Docket No. RM79–14, Order No. 49–A, issued December 27, 1979, 45 FR 767 (January 3, 1980).

[4] Petitions for rehearing of Order No. 49–A were filed by Man-Made Fiber Producers Association and American Hardboard Association. Requests for an interpretation were filed by Petrolite Corporation, Bareco Division; Universal Oil Products Company, Process Division; and National Steel Corporation, Great Lakes Steel Division. A request for an adjustment or interpretation was filed by Knowlton Brothers, Southern Cellulose Division.

C. SIC Code 2823 Cellulosic Man-Made Fibers

In a petition for rehearing of Order No. 49–A, Man-Made Fiber Producers Association (Man-Made) proposed the addition of SIC Code 2823 to § 282.202(a). The manufacture of cellulosic man-made fibers (SIC Code 2823) involves the processing of pulp (cellulose), a fibrous substance derived from wood, into man-made fibers such as rayon, acetate, and triacetate. The Commission believes that wood pulp is a natural fiber and, thus, the processing of wood pulp is "natural fiber processing." Accordingly, SIC Code 2823 is added to § 282.202(a).

Man-Made also requested that the Commission determine that the processing by textile mills of the man-made fibers themselves is "natural fiber processing." The Commission does not grant this request, because, by this stage in the manufacturing process, the material being processed is no longer natural fiber. The processing of rayon, acetate, and triacetate can no longer be characterized as "natural fiber processing" but instead is the processing of synthetic man-made fibers and, thus, does not qualify as an agricultural use.

In comments filed in this docket, Man-Made requested that the Commission clarify that natural fiber processing "includes processing of fabrics composed of blends of cotton and other natural fibers with man-made fibers." The Commission rejected this request when it stated in Docket No. RM80–16 that, "in the case of textile mills which process or produce a product that is a combination of natural and synthetic fibers, the volume of natural gas which shall be exempt is limited to the portion of natural gas related to processing the natural fiber in the blend."[6]

D. SIC Code 2899 Chemicals and Chemical Preparations, Not Elsewhere Classified—Chemical Cotton (Processed Cotton Linters)

The Southern Cellulose Products Division of Knowlton Brothers filed an application for an interpretation or an adjustment requesting a determination that natural gas used as boiler fuel in the processing of cotton linters is an agricultural use under section 206(b) of the NGPA, and, as such, is exempt from incremental pricing. In the Notice, the Commission proposed to include the processing of cotton linters in § 282.202(a), and no comments were received in opposition.

Cotton linters are short fuzzy fibers that adhere to cottonseed after the cotton ginning operation has removed the staple cotton, or lint fibers. The cotton linters are processed into cotton linter pulp which is then used in the production of other products. Since the Commission has determined that cotton is a natural fiber, the processing of cotton linters into pulp is "natural fiber processing," and, as such, is an agricultural use. The Commission therefore is adding SIC Code 2899 (processed cotton linters) to § 282.202(a).[7]

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[5] At a public hearing held on June 3, 1980, AWPI also requested that the Commission include this SIC Code retroactively to the inception of the incremental pricing program. The Commission denies the request. To retroactively include this code would result in an additional administrative burden that would far outweigh the overall benefit to be gained.

[6] Order No. 86, Docket No. RM80–16, issued May 8, 1980, at 7–8, 45 FR 31,983 (May 15, 1980).

[7] One commenter questioned the necessity of adding SIC Code 2899, stating that the code was already included as part of the original list certified by the Secretary of Agriculture. However, SIC Code 2899 Chemicals and Chemical Preparations, n.e.c. (salt—food and feed grade only) is not listed in § 282.202(a) because that code applies only to process and feedstock uses of natural gas (which uses are not currently subject to incremental pricing). The exemptions adopted in this rulemaking apply only to the boiler fuel use of natural gas.

E. Manufacture of Food Preservative BHA

The Process Division of Universal Oil Products Company filed a request for an interpretation that natural gas used to produce the food preservative butylated hydroxyanisole (BHA) is exempt from incremental pricing as an agricultural use. In the Notice, the Commission proposed to include such use in § 282.202(a), because BHA is necessary for "food quality maintenance." No comments were received in opposition.

Upon consideration, the Commission has determined that BHA is a preservative that is necessary for food quality maintenance. Accordingly, the manufacture of BHA is added to the definition of agricultural use.

F. Manufacture of Food-Grade Microcystalline and Synthetic Paraffin Waxes

The Bareco Division of Petrolite Corporation requested an interpretation that its boiler fuel use of natural gas in the manufacture of food-grade microcrystalline and synthetic paraffin waxes is an agricultural use. The manufacture of food-grade waxes, as entire food containers, was certified as an "essential agricultural use" by the Secretary of Agriculture (Secretary) on July 2, 1980 (45 FR 45887, July 8, 1980). Any use of natural gas certified by the Secretary after October 15, 1979, the initial effective date of § 282.202(a), is considered by the Commission on a case-by-case basis. (Docket No. RM80–75, Interim Rule, issued October 6, 1980, 45 FR 67276, October 9, 1980.)

Food-grade wax is used both as a protective coating on foods such as cheeses, fruits, and vegetables, and as a necessary coating for many food packages, including milk cartons, frozen food packages, and meat wraps.

In the Notice, the Commission stated that it was inclined to determine that the manufacture of food-grade microcrystalline and synthetic paraffin waxes is an agricultural use because food-grade waxes appear to be necessary for food quality maintenance. However, upon further consideration, and upon review of the Secretary's action with respect to the manufacture of food-grade waxes, the Commission has determined that not all such manufacturing is an agricultural use. The Commission's definition of agricultural use in § 282.202(a) includes the SIC Codes relating to the manufacture of food-related metal cans, glass jars, and paper cartons, because the manufacture of such containers is necessary for "food quality maintenance." Food-grade wax, when used to coat cheeses, fruits, or vegetables, constitutes the entire food package and provides much the same protection as would a metal can, a glass jar, or a paper carton. Accordingly, the Commission adopts the Secretary's certification of natural gas used in the production of food-grade petroleum wax, synthetic petroleum wax, and polyethylene wax for use as entire food containers and amends § 282.202(a) to include such use.

On the other hand, the use of food-grade wax as an essential coating or lining for food packages is a secondary input with respect to the manufacture of food packages. This use of food-grade wax is similar to the use of paper, paperboard, glue, sheet steel, and other materials purchased by food packaging manufacturers. The production of these materials is not an agricultural use relating to "food quality maintenance."[8] The Commission agrees with the Secretary's statement that:

> **[T]o include the production of food grade waxes which become an input for paper coating and glazing would constitute unequal treatment for similar kinds of inputs which have been regarded as secondary to the food quality maintenance function of actually fabricating containers. (45 FR 45888.)**

For these reasons, the Commission has determined that the production of food-grade wax for use as a coating or

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[8] However, the production of some of these materials may be included in the definition of agricultural use as "natural fiber processing."

lining for food packaging materials is a secondary input into the manufacture of food packaging and, thus, is not an agricultural use of natural gas.

G. Production of Steel Used in the Manufacture of Metal Food Cans

The Great Lakes Steel Division of Natural Steel Corporation requested an interpretation that its use of natural gas in the production of steel for use in the manufacture of food cans is an agricultural use.[9] As stated in the Notice, the Commission is of the view that natural gas used in the production of steel which in turn is processed into tinplate for use in the manufacture of food cans does not qualify as an agricultural use as defined in section 206(b) of the NGPA. As noted above, while food packaging industries are included in the definition of agricultural use, the production of food packaging materials is not a primary input into the food quality maintenance chain and, therefore, is not an agricultural use of natural gas. Only the manufacture of the container, not the production of the material from which it is made, qualifies for inclusion in § 282.202(a).

The Commission's determination is consistent with the determination by the Secretary to include the manufacture of metal food cans in the list of essential agricultural uses, but to exclude the production of steel, because it is a secondary or tertiary input into the food system. (*See* Department of Agriculture's Interim Final Rule, Part 2900—Essential Agricultural Uses and Volumetric Requirements—Natural Gas Policy Act, 44 FR 11518, 11522 (March 1, 1979).)

H. Production of Food-Grade Tin Used in the Manufacture of Metal Food Cans

Proler International Corporation proposed that the production of food-grade tin which is used in the manufacture of metal food cans be added to § 282.202(a). The Commission does not adopt this proposal for the reasons stated above relating to the production of materials used in the manufacture of food packaging.

I. SIC Code 3412 Metal Shipping Barrels, Drums, Kegs, and Pails (Agricultural Related Only)

The Steel Shipping Container Institute argued in comments filed in this docket that natural gas used to produce metal shipping barrels, drums, kegs and pails used for storing agricultural chemcials and foods should be exempt from incremental pricing as an agricultural use.

With regard to shipping containers used for storing agricultural chemicals necessary for agricultural production, the manufacture of such containers is clearly not a primary input into the food chain, as is the manufacture of food packages, and, therefore, is not an agricultural use.

However, the Commission believes that the manufacture of shipping containers used for storing foods is an agricultural use. On July 2, 1980, the Secretary certified SIC Code 3412 (*food* related only) as an essential agricultural use of natural gas. (45 FR 50549, July 8, 1980.) As noted above, uses certified as "essential agricultural uses" by the Secretary after October 15, 1979, are not automatically adopted by the Commission as "agricultural uses" for incremental pricing purposes, but are considered on a case-by-case basis. Based upon a consideration of the comments received in this docket and the Secretary's rationale for certifying SIC Code 3412 (food related only), the Commission has determined the use of natural gas in the manufacture of shipping containers used to package foods is an agricultural use. The Commission views such use of natural gas as indistinguishable from other agricultural uses of natural gas for the manufacture of sanitary food containers and food packaging necessary for food quality maintenance. Accordingly, SIC Code 3412 (food related only) is added to § 282.202(a).

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[9] Great Lakes Steel has also submitted written comments in this docket. In addition, the Jones & Laughlin Steel Corporaton filed written comments supporting the position taken by Great Lakes Steel.

J. SIC Code 28332 21 Naturally Occurring Vitamins (From Yeast, Plants, Fish, Liver, etc.) and SIC Code 28995 98 Other Industrial Chemical Specialities, Not Elsewhere Classified (Starch Graft Polymers)

Henkel Corporation filed written comments urging the Commission to add the two SIC Codes referenced above to § 282.202(a). SIC Code 28332 21 encompasses the production of naturally occurring vitamins utilized in nutritional and dietary supplements. The Commission believes that, since naturally occurring vitamins are a component of food, their manufacture is "food processing," and, as such, is within the definition of agricultural use. For this reason, the use of natural gas in the production of naturally occurring vitamins is added to § 282.202(a).

Starch graft polymers (SIC Code 28995 98) are produced by a reaction of pre-gelatinized corn starch with an acrylic monomer and are used primarily to hold moisture in soil and to aid in seed germination. Because starch graft polymers are neither food nor natural fiber, their production cannot be characterized as food or natural fiber production or processing. Instead, the production of starch graft polymers represents a secondary input into the food chain, and, as such, is not an agricultural use. Accordingly, SIC Code 28995 98 is not added to § 282.202(a).

K. SIC Code 3523 Farm Machinery and Equipment and SIC Code 3448 Prefabricated Metal Buildings and Components

The Butler Manufacturing Company (Butler) proposed the addition to § 282.202(a) of the SIC Codes listed above representing the manufacturing of farm machinery and equipment (such as cattle feeding equipment, crop dryers, feed grinders, incubators, silo filters and unloaders, fertilizer spreaders, and barn cleaners) and prefabricated metal buildings (such as storage bins and silos). Butler argued that the boiler fuel use of gas in the manufacture of such equipment and buildings is an agricultural use because farm equipment is a primary input into the food chain system, and prefabricated metal buildings have a close and vital connection to food production and food processing.

The Commission notes that while such manufacturing operations are certainly part of the "agricultural production" chain, these operations are at least one step removed from the actual production or processing of the agricultural product itself. The definition of agricultural use in § 282.202(a) as it relates to "agricultural production" is generally limited to those SIC Codes representing the on-farm use of natural gas for the production of crops or the raising of livestock. Similarly, the definition of agricultural use in § 282.202(a) as it relates to "food processing" is limited to the SIC Codes representing the actual production, preparation or processing of the food product. This distinction is analogous to the distinction the Commission has made in this rule between the manufacture of steel or tin used to make food cans, and the manufacture of the food cans themselves. The former, while part of the "food quality maintenance" chain, is at least one step removed from the "food quality maintenance" of the food itself. Accordingly, Butler's proposal to adopt these additional SIC Codes is rejected.

L. SIC Code 2869 (Production of Carbon Disulfide)

The Stauffer Chemical Company proposed the inclusion within the agricultural use definition of the production of carbon disulfide which is used in the direct processing of wood pulp into rayon and other cellulosic products. However, Stauffer stated that natural gas is used as process fuel in the production of carbon disulfide and not as boiler fuel. Since the scope of the incremental pricing program presently extends only to natural gas used as boiler fuel, the natural gas used in the production of carbon disulfide is not subject to incremental pricing. Accordingly, it is not necessary for the Commission to consider adding SIC Code 2869 to § 282.202(a) at this time.

M. SIC Codes 2841, 2843, 2869 and 2899 (Agricultural Raw Material Only)

The Humko Sheffield Chemical Division of Kraft, Inc. filed written comments requesting the Commission to include in § 282.202(a) the processing of agricultural products and byproducts (such as tallow, fish oils, vegetable oils, and tall oils) into chemical intermediates (such as fatty acids, fatty amides, fatty amines, dimer acids and glycerine) for use in producing plastics, lubricants, detergents, food emulsifiers, pharmaceuticals and textiles. The Commission believes that the described processes are too far removed from the food chain to qualify as agricultural uses. Although the raw materials which are processed may be agricultural in nature, the processing of these materials does not constitute "food processing" or "natural fiber processing." Accordingly, the above-referenced SIC Codes are not added to § 282.202(a).

IV. Effect of Alternative Fuel Test

The amendment adopted in this final rule allows an exemption for the subject uses until such time as the Commission promulgates a rule, pursuant to section 206(b)(2) of the NGPA, determining that an alternative fuel is economically practicable and reasonably available for such agricultural uses or users. All exemptions encompassed by § 282.202(a) will become subject to the provisions of such a rule upon its effective date. (*See* 18 CFR 282.203(b).)

V. Effective Date

The final rule is effective immediately, in accordance with 5 U.S.C. 553(d)(1), because it establishes exemptions [10] from the Commission's incremental pricing regulations.

(Natural Gas Policy Act of 1978, Pub. L. 95–621, 92 Stat. 3350 (15 U.S.C. 3301–3432)

In consideration of the foregoing, § 282.202(a)(1) of Part 282 of Subchapter I, Chapter I, Title 18, *Code of Federal Regulations* is amended as set forth below, effective December 5, 1980.

By the Commission.

Kenneth F. Plumb,

[¶ 30,216]

45 F. R. 84034 (December 22, 1980)

18 CFR Part 271

[Docket No. RM79-76 (Colorado—4); Order No. 116]

High-Cost Gas Produced From Tight Formations

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR § 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Colorado Oil and Gas Conservation Commission that the Fort Union Formation, the Mesa Verde Formation, and Mancos Formation to the base of the Mancos "B" Zone be designated as tight formations under § 271.703(d).

EFFECTIVE DATE: This rule is effective December 17, 1980.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8299, or Victor Zabel, (202) 357–8559.

SUPPLEMENTARY INFORMATION:

Issued: December 17, 1980.

The Commission hereby amends § 271.703(d) of its regulations to include the Fort Union Formation, the Mesa Verde Formation and the Mancos Formation to the base of the Mancos "B"

Zone as designated tight formations eligible for incentive pricing under § 271.703. The amendments were proposed in a Notice of Proposed Rulemaking by the Director, OPPR, issued October 10, 1980, (45 FR 69929, October 22, 1980) [1] based on a recommendation by the Colorado Oil and Gas Conservation Commission (Colorado) in accordance with § 271.703(c).

Evidence submitted by Colorado and one commenter supports Colorado's assertion that these Formations meet the guidelines contained in § 271.703(c)(2). The Commission concurs with Colorado's recommendation.

These amendments will become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available creates good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3101–3432; Administration Procedure Act, 5 U.S.C. § 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective December 17, 1980.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,217]

45 F. R. 84035 (December 22, 1980)

18 CFR Part 271

[Docket No. RM 79-76 (Colorado-6); Order No. 115]

High-Cost Gas Produced From Tight Formations

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Colorado Oil and Gas Conservation Commission that the Mancos "B" Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective December 17, 1980.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8299, or Victor Zabel, (202) 357–8559.

SUPPLEMENTARY INFORMATION:

Issued: December 17, 1980.

The Commission hereby amends § 271.703(d) of its regulations to include the Mancos "B" Formation as a designated tight formation eligible for incentive pricing under § 271.703. The amendments were proposed in a Notice of Proposed Rulemaking by the Director, OPPR, issued October 15, 1980, (45 FR 69931, October 22, 1980)[1] based on a recommendation by the Colorado Oil and Gas Conservation Commission (Colorado) in accordance with § 271.703(c) that the Mancos "B"

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[1] Comments were invited and one was received. No party requested a hearing in this proceeding, and no hearing was held.

[1] Comments were invited and one was received. No party requested a hearing in this processed, and no hearing was held.

Formation be designated as a tight formation.

Evidence submitted by Colorado and the commenters supports Colorado's assertion that Mancos "B" Formation meets the guidelines contained in § 271.703(c)(2). The Commission concurs with Colorado's recommendation.

The amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available creates good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.;* Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3101–3432; Administrative Procedure Act, 5 U.S.C. § 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective December 17, 1980.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,218]

45 F. R. 84036 (December 22, 1980)

18 CFR Part 271

[Docket No. RM79-76 (New Mexico—1); Order No. 118]

High-Cost Gas Produced From Tight Formations; Final Rule

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR § 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the New Mexico Oil Conservation Commission that the Austin-Mississippian Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective December 17, 1980.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8299, or Victor Zabel, (202) 357–8559.

Issued December 17, 1980.

Before Commissioners: Georgiana Sheldon, Acting Chairman; Matthew Holden, Jr., and J. David Hughes.

The Commission hereby amends § 271.703(d) of its regulations to include the Austin-Mississippian Formation as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by the Director, OPPR, issued October 16, 1980, (45 FR 63932, October 22, 1980)[1] based on a recommendation by the New Mexico Oil Conservation Commission (New Mexico) in accordance with § 271.703(c) that the Austin-Mississippian Formation be designated as a tight formation.

Evidence submitted by New Mexico and one commenter supports New Mexico's assertion that this formation meets the guidelines contained in § 271.703(c)(2). The Commission concurs with New Mexico's recommendation.

The amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available creates good cause to waive the thirty-day publication period.

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[1] Comments were invited and one was received. No party requested a hearing in this proceeding, and no hearing was held.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. 3101–3432; Administrative Procedure Act, 5 U.S.C. 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective December 17, 1980.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,219]

45 F. R. 84036 (December 22, 1980)

18 CFR Part 271

[Docket No. RM79-76 (Texas-2); Order No. 117]

High-Cost Gas Produced From Tight Formations; Final Rule

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR § 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Texas Railroad Commission that the Canyon Sandstone Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective December 17, 1980.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8299, or William Bushey, (202) 357–8590.

The Commission hereby amends § 271.703(d) of its regulations to include the Canyon Sandstone Formation as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by the Director, OPPR, issued October 2, 1980, (45 FR 66912, October 8, 1980)[1] based on a recommendation by the Texas Railroad Commission (Texas) in accordance with § 271.703(c).[2]

Evidence submitted by Texas and the Commenters supports Texas' assertion that the Canyon Sandstone Formation meets the guidelines contained in § 271.703(c)(2). The Commission concurs with Texas' recommendation.

This amendment will become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available creates good cause to waive the thirty day publication period.

(Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3101–3432; Administrative Procedure Act, 5 U.S.C. § 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective December 17, 1980.

By the Commission. Commissioner Hughes voted present.

Kenneth F. Plumb,
Secretary.

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[1] Comments were invited and three comments were received. No party requested a hearing in this proceeding and no hearing was held.

[2] In a letter to the Commission dated November 19, 1980, Texas submitted additional information clarifying the depth at which the recommended formation is encontered.

Regulations Preambles

46 Federal Register (1981)

[¶ 30,220]

46 F. R. 1666 (January 7, 1981)

18 CFR Part 282

[Docket No. RM81-1; Order No. 120]

Incremental Pricing; Natural Gas Users in Rhode Island

Issued: December 30, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: This final rule adopts revised alternative fuel price ceilings applicable to incrementally priced natural gas users in Rhode Island for the months of May through September 1980. The ceilings are revised to correct an error in data submitted to the Energy Information Administration by oil suppliers in Rhode Island. These corrected prices were first published in an interim rule issued in this docket on October 3, 1980 (45 FR 68389, October 15, 1980). Section 282.404(a) of the Commission's regulations is amended to provide corrected alternative fuel price ceilings for Rhode Island for the months of May through September 1980 in place of the alternative fuel price ceilings previously published by the Energy Information Administration of the Department of Energy.

EFFECTIVE DATE: January 29, 1981.

FOR FURTHER INFORMATION CONTACT:
Barbara Christin, 202-357-8033, or
Leslie Lawner, 202-357-8299

SUPPLEMENTARY INFORMATION: In the matter of rule adopting revised alternative fuel price ceilings for the State of Rhode Island; Final rule.

I. Introduction

The Federal Energy Regulatory Commission (Commission) is adopting, as a final rule, an interim rule that corrected the alternative fuel price ceilings applicable to incrementally priced natural gas users in the State of Rhode Island for the months of May through September 1980. The interim rule (issued October 3, 1980, 45 FR 68389, October 15, 1980) amended § 282.404(a) to provide that the alternative fuel price ceilings for Rhode Island for the months of May through September 1980 are the ceilings set forth in § 282.404(a)(2), rather that the ceilings previously published by the Energy Information Administration (EIA) of the Department of Energy.

II. Background and Discussion

Title II of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3301-3432) requires the Commission to prescribe and make effective a program of incremental pricing of natural gas used as industrial boiler fuel. Section 204(e) of the NGPA directs the Commission to establish ceilings on prices charged to incrementally priced users, based on the cost of alternative fuel oils in each region designated by the Commission.

Under the Commission's incremental pricing regulations, ceiling prices for each month are based on the observed price of high-sulfur No. 6 fuel oil in each of the 48 contiguous states. These ceiling prices are published in the **Federal Register** on, or before, the twentieth day of the month preceding their effective date. The collection of data, the calculation of the price ceilings, and the publication of these ceilings are performed by the EIA, in accordance with its statutory responsibilities. (Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; Department of Energy Delegation Order No. 0204-3, October 1, 1977.)

For the months of May through September 1980, the alternative fuel price ceilings were calculated erroneously, due to an error in the data submitted to the EIA by an oil supplier in the State of Rhode Island. Upon learning of the error, the Commission asked the EIA to recompute the alternative fuel price ceilings for all states for May through September 1980, using the corrected data. The recalculated figures indicated, that with respect to the 47 contiguous states other than Rhode Island, there was either no difference between the revised ceilings and the published ceilings, or the revised ceilings were only slightly higher than the published ceilings. However, the revised ceilings for Rhode Island were significantly lower than the published ceilings.

On the basis of this information, the Commission issued the interim rule on October 3, 1980, amending § 282.404 of the Commission's regulations to provide that the revised alternative fuel price ceilings for Rhode Island, for May through September 1980, supersede the ceilings that were previously published by the EIA. In view of the small or non-existent difference between the published and the revised ceilings for the other 47 contiguous states, the Commission did not revise the ceiling prices for those states, finding that any benefits would be outweighed by the administrative burden such revisions would impose upon pipelines, distribution companies, and end-users.

The interim rule did not provide for the refund of surcharges in Rhode Island, because no surcharges had been collected from the affected end-users. The Providence Gas Company, which serves all the non-exempt customers in the State, had notified its customers of these surcharges, but had not collected them prior to issuance of the interim rule. Therefore, Providence Gas had only to recalculate and submit revised bills to its customers.

In the interim rule, the Commission found good cause, in accordance with 5 U.S.C. 553(b) and (d), to waive the normal notice and comment procedures as well as the thirty day publication requirement. Accordingly, the rule was effective upon issuance. However, the Commission requested written comments and afforded the opportunity for a public hearing on the interim rule. No person submitted comments or requested that a hearing be held.

For the reasons discussed in the interim rule and summarized above, the Commission is adopting the interim rule as a final rule.

II. Effective Date

The final rule set forth below is effective on January 29, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432)

In consideration of the foregoing, the Commission amends Part 282, Subchapter I, Chapter I, Title 18 of the *Code of Federal Regulations* as set forth below, effective January 29, 1981.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,221]

46 F. R. 2036 (January 8, 1981)

18 CFR Part 282

[Docket No. RM81-9]

Incremental Pricing; Rule Adopting Revised Alternative Fuel Price Ceilings for the State of Kentucky

Issued December 24, 1980.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Interim rule.

SUMMARY: This rule amends § 282.404(a) of the Commission's regulations implementing the Natural Gas Policy Act of 1978. Specifically, the amendment provides that the alternative fuel price ceilings applicable to the State of Kentucky for December 1980 and January 1981 are the ceilings set forth in § 282.404(a)(3), rathe: than the ceilings previously published by the Energy Information Administration (EIA). The Commission is taking this action on the basis of its finding that the substantial differential between the price ceilings in Kentucky and those in the neighboring state of Ohio should be reduced, on an interim basis, until such time as the Commission acts in the generic rulemaking (Notice of Inquiry, Docket No. RM79-21, 45 FR 74505, November 10, 1980) dealing with alternative fuel ceiling prices.

The Commission is also directing the EIA to publish the Region D ceiling price, rather than the state price, for Kentucky for the months following January 1981, until the Commission acts in Docket No. RM79-21.

DATES: Interim Rule effective December 24, 1980. Comments due: January 23, 1981. Public Hearing: January 19, 1981.

ADDRESSES: All comments and requests to participate to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE, Washington, D.C. 20426. Public Hearing to be held at: Federal Energy Regulatory Commission, 825 North Capitol Street, NE, Washington, D.C. 20426 (Room to be announced).

FOR FURTHER INFORMATION CONTACT: Thomas Gross, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE, Washington, D.C. 20426, (202) 357-8077 (or) Colette Bohatch, Office of the General Counsel, (202) 357-8140.

I. Introduction

The Federal Energy Regulatory Commission (Commission) is amending, on an interim basis, its regulations on incremental pricing (18 CFR Part 282) under Title II of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3301-3432). Specifically, § 282.404(a) is amended to provide that the alternative fuel price ceilings for Kentucky, for the months of December 1980 and January 1981, are the ceilings set forth in § 282.404(a)(3), rather than the ceilings previously published by the Energy Information Administration (EIA) of the Department of Energy. Further, the Commission is directing the EIA to publish the regional alternative fuel price ceiling for Region D as the alternative fuel price ceiling for Kentucky for months following January 1981, until the Commission takes final action on the generic rulemaking in Docket No. RM79-21.

II. Background

Title II of the NGPA requires the Commission to prescribe and make effective a program of incremental pricing of natural gas used as industrial boiler fuel. Section 204(e) of the NGPA directs the Commission to establish ceilings on gas prices charged to incrementally priced users, based on the cost of alternative fuel oils in each region designated by the Commission.

Under the Commission's regulations implementing section 204(e), alternative fuel price ceilings for each month are published in the **Federal Register** on, or before, the twentieth day of the month preceding their effective date. The ceiling for each region is calculated by a formula which uses the price of high-sulfur No. 6 fuel oil observed in that region during a previous period. The collection of data, the application of the formula, and the publication of the ceilings are performed by the EIA, in accordance with its statutory responsibilities. (Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; Department of Energy Delegation Order No. 0204-3, October 1, 1977.)

In its initial regulations implementing the incremental pricing program (Docket No. RM79-21, Order No. 50, issued September 28, 1979, 44 FR 57754, October 5, 1979), the Commission implemented two sets of designated regions: (1) 48 regions, each region being one of the 48 continental states; and (2) eight multistate regions, labeled Regions A through H. The 48 state regions are to be used for purposes of calculating the regional alternative fuel price ceilings. However, if available data for a particular state are insufficient to permit calculation of a price ceiling for that state, the price ceiling for that state is the price ceiling calculated for the multistate region in which the state is located.

Due, in part, to its recognition that, in some cases, alternative fuel price ceilings vary significantly in neighboring states, raising questions of inequity and possible fuel switching, the Commission recently instituted a rulemaking proceeding in Docket No. RM79-21 for the purpose of re-examining both the designation of incremental pricing regions and the methodology for calculating the price ceilings in those regions. On November 4, 1980, the Commission issued a Notice of Inquiry (Notice) in that docket (45 FR 74505, November 10, 1980), requesting public comment on possible revisions suggested in the Notice.

In other dockets, several persons filed documents with the Commission, stating that the published alternative fuel price ceilings for Kentucky are inequitably and substantially higher than the price ceilings in neighboring states. These persons have urged the Commission to eliminate the inequity by substituting the price ceiling calculated for the multistate region in which Kentucky is located (Region D) for the price ceiling calculated for Kentucky. The substance of these filings is discussed below.

III. Discussion

On October 7, 1980, Armco, Inc. (Armco) filed with the Commission, in Docket No. SA81-1-000, an application for a staff adjustment pursuant to section 502(c) of the NGPA and § 1.41 of the Commission's regulations. Armco stated that under the incremental pricing provisions of Title II of the NGPA and under the Commission's regulations, Armco has been required to pay incremental pricing surcharges that have raised the price it pays for natural gas substantially above both the national average and the average in its neighboring state of Ohio. Armco requested that the Commission:

> Substitute for the posted price in the State of Kentucky the regional average price, notwithstanding that there may have been technically sufficient sales in each of the test months to trigger the operation of the methodology contained in Order Nos. 50 and 51 rather than substituting the regional average.[1]

Similarly, on November 26, 1980, the Commission received an application for a staff adjustment pursuant to section 502(c) of the NGPA from Louisville Gas and Electric Company (Louisville), in Docket No. SA81-9-000, stating that the price ceiling for Kentucky has consistently exceeded the alternative fuel price ceilings for each of the remaining Region D states by a substantial margin. Louisville requested the Commission to issue a clarifying amendment to Order No. 50 requiring the EIA to use regional sales data when statistically valid price data are unavailable for the state region.

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[1] Armco's Supplemental Application for a Staff Adjustment, Docket No. SA81-1-000 filed October 14, 1980.

On November 5, 1980, the Commission received a letter from the Office of the Secretary, the Kentucky Department of Energy (KDOE) stating, among other things, that the price ceiling in the State of Kentucky is not based on a valid statistical sample. KDOE urged that the Commission "place the Kentucky incremental natural gas ceiling price at the regional price and that the action be made retroactive to August 1, 1980."

On December 10, 1980, the Associated Industries of Kentucky and Dow Corning Corporation (collectively Petitioners) filed with the Commission, in Docket No. RM79-21, a petition for an Interim Rule for the State of Kentucky pursuant to section 501(a) of the NGPA and § 1.7(b) of the Commission's regulations.[2] In their application, Petitioners state that Kentucky's price ceiling is unfairly and unreasonably high due to the EIA methodology and will result in fuel switching. Petitioners requested the Commission to issue an interim rule for the State of Kentucky which will use the sales of high-sulfur No. 6 fuel oil in a multistate region[3] for computing the price ceiling for Kentucky.

The Commission notes that there has been a recurring substantial price differential between the published price ceilings for the States of Kentucky and Ohio as the following list indicates:

	Kentucky (MMBtu)	Ohio (MMBtu)
September, 1980	3.51	2.20
October, 1980	3.50	2.14
November, 1980	3.49	2.11
December, 1980	3.41	2.29
January, 1981	4.35	2.87

As discussed above, the Commission is analyzing, in the context of the generic rulemaking in Docket No. RM79-21, the differences in the alternative fuel price ceilings among nearby states and the possibility of undesirable and unnecessary fuel switching or inequities among competing companies. The Commission has accorded a high priority to this rulemaking and is currently considering alternative methodologies for computing the price ceilings. However, comments submitted at informal public conferences conducted in connection with that rulemaking proceeding have urged the Commission to devote additional study to potential revisions before formulating a generic rule revising the current methodology. The Commission agrees, but recognizes that the time required for additional study will preclude, in the interim, providing to incrementally priced end users in Kentucky relief that might result from the generic rulemaking revising the methods for computing alternative fuel price ceilings.

The Commission has investigated the oil and gas transactions in Kentucky and Ohio and the manner in which the alternative fuel price ceilings reflect those transactions. The Commission is persuaded that until such time as the substantial price differential between these states is addressed in the generic rulemaking in Docket No. RM79-21, good cause exists to reduce this differential on an interim basis.

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[2] The issuance of this interim rule will serve as notice of petitioner's application for an interim rule.

[3] Petitioner states that the Commission could use either the multistate regional grouping originally suggested in Order No. 50 (Region D), or the revised grouping suggested in the Commission's Notice of Inquiry issued November 4, 1980, Docket No. RM79-21.

When this matter is taken up in the context of the generic rulemaking, the differences between the Ohio and Kentucky ceilings may, in fact, be found to be warranted. However, because the Commission has decided to proceed with further study before acting on a generic rule, it believes the public interest requires interim action to prevent any disadvantage or inequity to incrementally priced users in Kentucky.

Accordingly, the Commission believes that good cause exists to direct the EIA to use the Region D price ceiling as the price ceiling for Kentucky, pending final action in Docket No. RM79-21.

Because any incremental pricing surcharges incurred in December 1980 will not be billed until the beginning of January 1981, the regional methodology is made effective for the billing month of December 1980. The Commission denies the request of KDOE to make the rulemaking retroactive to August 1, 1980, because surcharges incurred before December, 1980 have already been billed. The administrative burdens to interstate pipelines and local distribution companies of making adjustments to those surcharges at this time outweigh any benefit to be gained.

In order to effect application of this regional methodology with respect to the months of December 1980 and January 1981, this rulemaking adds § 282.404(a)(3) to the Commission's incremental pricing regulations. The new section establishes that the Region D price ceilings for December 1980 and January 1981 supersede the alternative fuel price ceilings for Kentucky previously published by the EIA. Based on data provided by the EIA, the Region D price ceiling is $2.70/MMBtu for December 1980 and is $3.28/MMBtu for January 1981.

In order to effect application of the regional methodology with respect to months following January 1981, until the time the generic rulemaking is completed, the Commission is requesting the Executive Director of the Commission to send an amended Data Services Request (DSR) to the EIA. The DSR will direct the EIA to publish the regional average price ceiling for Region D as the price ceiling for Kentucky, until the Commission takes final action on the generic rulemaking in Docket No. RM79-21. The interim rule amends Appendix I to Subpart D of Part 282 to conform to this change.

IV. Effective Date

The Commission believes that because it has decided to proceed with further study before acting on a generic rule, failure to grant immediate relief to incrementally priced end-users in Kentucky would be contrary to the public interest. Accordingly, the Commission finds that good cause exists in accordance with 5 U.S.C. 553(b) and (d) to make this rule effective immediately as an interim rule, applicable to the price ceilings for Kentucky for December 1980 and thereafter until the Commission takes final action on the generic rule in Docket No. RM79-21. The Commission will afford an opportunity for interested persons to present views and comments, as set forth below, before the rule is adopted in final form.

V. Comment Procedures

A. Written Comments

Interested persons are invited to submit written comments, data, views, or arguments with respect to this interim rule. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, and should reference Docket No. RM81-9. An original and 14 copies should be filed. All comments received prior to 4:30 p.m. EST, January 23, 1981, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection through the Commission's Division of Public Information, Room 100, 825 North Capitol Street NE., Washington, D.C., during regular business hours.

B. Public Hearing

Interested persons may request the opportunity for an oral presentation of their views at a public hearing. Requests for an oral hearing should be submitted no later than January 7, 1981, to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, and should reference Docket No. RM81-9. If any requests are received by that time, the hearing will be held on January 19, 1981, at the above address, and will be announced by January 12, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301 *et seq.*; Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; E.O. 12009, 3 CFR 142 (1978))

In consideration of the foregoing, the Commission amends Subpart D, Part 282, Subchapter I, of Chapter I, Title 18 of the *Code of Federal Regulations*, on an interim basis, as provided below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,222]

46 F. R. 6885 (January 22, 1981)

18 CFR Part 260

[Docket No. RM80-56; Order No. 121]

Order Revising Form No. 2 Annual Report of Natural Gas Companies (Class A and Class B)

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) hereby revises Form No. 2, "Annual Report of Natural Gas Companies (Class A and Class B)" (18 CFR 260.1). The revisions reduce the number of schedules and data elements contained in the form, establish or alter threshold reporting levels in certain schedules, and change reporting instructions in several schedules. These modifications reduce the data elements in Form No. 2 by approximately 20%. The changes to Form No. 2 reflect the results of an ongoing validation program to eliminate the reporting of data which is not necessary to the Commission's regulatory responsibilities and, thereby, to reduce the reporting burdens of jurisdictional companies which file that information with the Commission.

EFFECTIVE DATE: January 9, 1981.

FOR FURTHER INFORMATION CONTACT:

James Kitchen/Elaine M. Dawson, Office of Chief Accountant, Federal Energy Regulatory Commission, 825 North Capitol Street NE.; Room 3408-N/3405-N, Washington, D.C. 20426, (202) 357-9212/357-9190

Randolph E. Mathura/Donald Champagny, Office of Producer and Pipeline Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Room 3100-N/5300-E, Washington, D.C. 20426. (202) 357-9066/357-8806.

Issued: January 9, 1981.

I. Background

Form No. 2, "Annual Report for Natural Gas Companies (Class A and Class B)" is prescribed by the Federal Energy Regulatory Commission (Commission) pursuant to sections 10(a) and 16 of the Natural Gas Act (15 U.S.C. 717-717w).[1] The information collected in Form No. 2 primarily includes general corporate information; summary financial data; balance sheet supporting data; income statement supporting data; and gas plant, sales, operating and statistical data.

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[1] FERC Form No. 2 (Attachment C) is not being printed by the Federal Register. Copies of the Form No. 2 Final Rule, including all attachments, are available in the Commission's Office of Public Information. Blank copies of the form may be obtained from the Energy Information Administration.

On July 1, 1980, the Commission issued a Notice of Proposed Rulemaking (Notice) to revise Form No. 2 (45 46075, July 9, 1980). The revisions were proposed as part of the commission's ongoing effort to eliminate the reporting of information which is not needed for decisional purposes in the Commission's regulatory process. By eliminating the filing of information which is not needed by the Commission, the reporting burden of companies which file Form No. 2 with the Commission is reduced.

In the Notice, the Commission proposed to: eliminate the requirement for Certified Public Accountant certification on 15 of the 19 schedules presently requiring such certification, establish or revise threshold reporting levels on 13 of the schedules, revise the reporting instructions on 17 of the schedules, delete data from 10 schedules, and delete 33 schedules in their entirety. This was estimated to be a 19 percent reduction in the Commission-imposed reporting burden related to the Form No. 2.

In addition, the Commission specifically requested responses to five questions, which will be discussed in the next section. Pursuant to a request, the Commission extended the Form No. 2 rulemaking comment period until October 14, 1980 (45 FR 63001, September 23, 1980).

II. Summary of Comments and Changes to Form No. 2

In response to the proposed rulemaking, the Commission received thirty-nine comments. Of these, twenty-five were from natural gas companies which are required to file the report form, ten from state utility commissions, three from Certified Public Accountant firms, and one from a gas industry association.[2] The general reaction to the rulemaking was favorable. A number of changes were suggested by commenters, many of which have been incorporated into the Form No. 2, as discussed below and in the attached detailed discussion (Attachment A) [3] which responds to comments on a schedule-by-schedule basis. However, the Commission has not further discussed those schedules for which no comments had been submitted.

A. Responses to Specific Questions

The answers to five specific questions were requested by the Commission concerning the proposed revisions to the Form No. 2. The responses to these questions are analyzed sequentially.

1. (a) *Do the proposed revisions or eliminations of data affect any Commission or State regulatory functions?*

Of the ten state agencies which responded to the rulemaking, three indicated that revisions or eliminations to Form No. 2 would affect their regulatory responsibilities, five stated that revisions or eliminations would cause some partial effect on their responsibilities, one replied that there would be very little effect, and one claimed that the changes would have no effect.

1. (b) *Will State agencies now utilizing this report form in the exercise of their own regulatory responsibilities agree to reduce their reporting requirements concurrently?*

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[2] Interstate Natural Gas Association of America, Arthur Andersen & Co., Deloitte, Haskins & Sells, Price Waterhouse & Co., The Cincinnati Gas & Electric Company, Consolidated Gas Supply Corporation, East Tennessee Natural Gas (Tenneco), Iowa Illinois Gas and Electric Company, Iowa Power & Light Company, Iowa Public Service Company, Kansas Power and Light, Michigan Gas Storage Company, Michigan Wisconsin Pipe Line Company, Midwestern Gas Transmission (Tenneco), Natural Gas Pipeline Company of America, Northern Natural Gas Company, Northwest Pipeline Corporation, Orange & Rockland Utilities, Inc., Pacific Interstate Transmission Company, Pacific Gas and Electric Company, Panhandle Eastern Pipe Line Company, Public Service Company of Colorado, Public Service Electric and Gas Company, San Diego Gas & Electric, Southern Indiana Gas and Electric Company, Southern Natural Gas Company, Tennessee Gas Pipeline Company (Tenneco), Texas Gas Transmission Corporation, United Gas Pipe Line Company, California Public Utilities Commission, Colorado Public Utilities Commission, Georgia Public Service Commission, Idaho Public Utilities Commission, Kansas State Corporation, Maine Public Utilities Commission, Michigan Department of Commerce, Minnesota Public Utilities Commission, New Jersey Department of Public Utilities; and New York Department of Public Service.

[3] Attachment B is a comparison table of old Form No. 2 schedules and revised Form No. 2 schedules.

Thirty-one of the fifty states require Form No. 2, or some version of the Form No. 2 to be filed with them by natural gas companies within their jurisdiction.[4] Only ten of these thirty-one states responded to this rulemaking. Two said that they would probably continue to collect the data proposed for deletion in Form No. 2. Six indicated an interest in retaining at least a portion of the affected data. One state said that it would delete all of the data proposed for deletion. Finally, one state responded that it would collect the subject data only if it was specifically needed.

One state agency, and three jurisdictional companies which must file Form No. 2 with the Commission and also with a state agency identified a potential increase in reporting burden due to the Commission's deletion of information from Form No. 2 which was not also eliminated from the state requirements. One commenter alleged that the discontinuance of a reporting requirement by the Commission which is not also eliminated by its state agency only "shifts the reporting burden" from the Federal to the state level.

The Commission nevertheless believes it is in the public interest to delete information requirements from Form No. 2 even though that same data may, in some instances, continue to be collected by certain state agencies.[5] On the basis that only two state agencies may require all of the data proposed for deletion, and six others may require some of the data, the Commission cannot justify the retention of data which are not used in the Commission's decisionmaking process.[6] Retaining data not used by the Commission would penalize those companies which file Form No. 2 only with the Commission, and those companies whose state agency is revising its Form No. 2 requirements to correspond with the Commission's revisions. The burden in justifying the continued collection of the data will be at the state level.

2. *Is there any reason for continued collection of the data for the purposes of another Federal agency? Suggestions for the continued collection of data which have been proposed for elimination from the present Form No. 2 should identify the proper agency and the basis and purpose for its collection of the data.*

One commenter stated that the Securities and Exchange Commission may use some of the data in Form No. 2 which has been proposed for deletion or amendment. The comment urged that the data should be collected and disseminated by a single agency "in the interest of efficient regulation." No Federal agencies responed to the Notice.

The information which has been eliminated from Form No. 2 was not specifically shown to be necessary to the operations of any Federal agency. Furthermore, in our view, it should not continue to be collected by the Commission only for the purpose of convenience, if it is not otherwise required in Commission regulatory processes.

3. *What cost savings are likely to result from the proposed elimination of the CPA certifications?*

The Commission proposed to delete the certification requirement by Certified Public Accountants (CPAs) from fifteen schedules and retain it for the four basic financial statements: Balance Sheet, Income Statement, Statement of Retained Earnings, and Statement of Change in Financial Position. Sixteen of the jurisdictional companies responded to the question and agreed that some cost savings would result from the elimination of these CPA certifications. Estimates varied greatly, however, with respect to the amount of savings. Two state agencies addressed the question and stated that they did not believe that any cost savings would result. Three CPA firms responded to the question, and all three indicated that a cost savings would probably be realized.

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[4] Twenty-one states require the filing of the current Form No. 2; nine states require the filing of both Form No. 2 and a state report form; one state accepts Form No. 2 in lieu of its own report form.

[5] In the following schedule pages, the issue arose concerning the respective Form No. 2 reporting requirements of the Commission and state agencies. Since it is discussed above, this issue is not raised again in the discussions of the individual schedules (Attachment A): pp. 104, 110–111, 114, 115, 116, 116A, 204, 206, 207A, 208, 212, 214, 214A, 221, 224, 224A, 225, 229, 300, 303, 304, 305, 306, 351, 506–507, 509–512, 513, 515, 523, 528, 533A–533D, 535–536A, 542, 545–546B, 550–551, 552–553B, and 563.

[6] The Commission did not conduct a separate analysis of the regulatory needs of each state agency which requires a Form No. 2, nor did the Commission separately attempt to measure the magnitude of any increased burden due to the filing of two different forms by respondents. The comments filed by the state agencies in this docket were considered indicative of state Form No. 2 requirements and reporting burdens.

The Commission has deleted the certification requirement for the fifteen schedules because such deletions do not alter the validity of the form. The four basic financial statements are essentially summaries of information reported in detail elsewhere in the form, including the fifteen schedules. Certification of the fifteen schedules is, therefore, unnecessary since these schedules are reviewed in connection with the certification of the four basic statements.

One CPA firm recommended an alternative to the current certification statement which would be patterned after standards established in the American Institute of Certified Public Accountants, Statement on Auditing Standards No. 14, Special Reports.

However, the basic purpose of this rule is to eliminate unnecessary reporting. Changes in format and schedule revisions that require additional burden are beyond the scope of this effort. Nonetheless, the suggestion for an alternative certification statement will be taken under advisement for any future refinements to Form No. 2.

4. *What are the merits of using a percentage of the year end account balance rather than a selected fixed dollar figure in establishing a threshold for "minor items"?*

There was no consensus among the 14 responses to this question: seven suggested the use of a fixed dollar amount; four preferred use of a uniform percentage amount; and three others suggested some standardized combination of the two methods. Other commenters claimed that the thresholds on certain schedules were too high, too low, unnecessary, or that the thresholds should be conformed to the Form No. 1, "Annual Report for Electric Utilities, Licensees, and Others (Class A and Class B)."

All of the thresholds proposed in this proceeding were carefully established on a schedule-by-schedule basis according to the Commission's particular needs for details unique to each account or schedule page. In view of the lack of a preponderance of comments favoring a particular uniform threshold type or amount, the Commission, upon review of our requirements, has retained a schedule-by-schedule approach to setting thresholds. Moreover, we are unable to conform all thresholds to those in Form No. 1, because of differences in the Commission's regulation of gas and electric rates, which must be reflected in the reporting requirements.

Specific threshold issues which are peculiar to Form No. 2 pages 507, 524, 537, 540, 564, and 572–572A are discussed in the atached discussion of schedules (Attachment A).

5. *What is the effect of deleting the INDEX from the back of the report form?*

The majority of responses to this question favored the retention of the Index. Many commenters urged that it should be made more legible. The Commission agrees, and the Index has been retained and reprinted to enhance its usefulness.

B. Other General Issues

1. *Differences in format between the proposed form No. 1 and form No. 2.*

Several commenters who responded to the instant rulemaking raised issues with respect to a pending rulemaking at the Commission to revise Form No 1. Form No. 1 is the "Annual Report for Electric Utilities, Licensees and Others (Class A and Class B)" and is essentially the electric counterpart of Form No. 2. A Notice of Proposed Rulemaking to revise Form No. 1 was issued on July 10, 1980 (Docket No. RM80-55, 45 F.R. 47705, July 16, 1980). A Final Rule on Form No. 1 is expected in the near future, but any changes resulting from issuance of the Final Rule would only be effective for reports for calendar year 1981 reports and thereafter.[7]

Several schedules in Form No. 1 are currently identical or similar to Form No. 2 schedules. Companies which file both Form Nos. 1 and 2 with the Commission and/or with state agencies, have interchanged various pages in the forms, where possible, to avoid duplicate reports. Some commenters objected to certain proposed changes in Form No. 2 schedules, which were not made to the corresponding schedules in Form No. 1 and, conversely, to changes in Form No. 1 which did not appear in Form No. 2. Those companies which are required to complete both forms argued that common schedules of the forms should be treated similarly, so as to reduce their reporting burden.

The Commission has, wherever possible, made conforming changes to both forms,[8] including reorganizing and renumbering the pages. In many instances, however, the Commission found it necessary to require reports from jurisdictional gas companies which differ from those required from jurisdictional electric companies. The forms cannot be made identical for both gas and electric companies because the requirements differ pursuant to the distinct statutes and regulations prescribed for each of these types of operations. Furthermore, the Commission actually regulates a greater percentage of gas revenues (approximately 84 percent) than it does of the electric revenues (approximately 15 percent)—and this factor affects the type of reporting required. Specific issues which were raised in certain schedules with respect to the differences between Form Nos. 1 and 2 are examined in connection with the discussions of the particular schedules (Attachment A).

2. *Cost-benefit analysis.*

One commenter stated that a cost-benefit analysis should be considered with respect to the collection of data in Form No. 2. The commenter also suggested that an appropriate test could be developed by joint Commission/industry efforts.

We agree that cost/benefit analysis is an essential ingredient in weighing the need to collect data; however, it is not the sole criterion. The Commission must first consider which data are essential to its regulatory responsibilities, *i.e.*, data which are necessary and appropriate to the lawful administration of the various statutes which the Commission administers.

In the Commission's data-validation program, the following criterion for retaining data has been used: Is the information to be retained in a reporting requirement *essential* to the decision-making process at the Commission? Cost/benefit factors are considered; however, the need for decision-making support, and legal requirements for substantial evidence to justify Commission decisions, must be paramount.

III. Public Procedure and Effective Date

The Commission has complied with 5 U.S.C. 553 by having provided public notice and an opportunity to participate in this rulemaking. Adoption of this Final Rule, including the discussion of the individual schedules (Attachment A) will eliminate a requirement imposed on industries regulated by the Commission. Therefore, the Commission finds good cause to waive the 30-day requirement set forth in 5 U.S.C. 553(d) and to make the Final Rule effective immediately. Thus, Form No. 2 will be revised as of the date of issuance of this Final Rule, and the new Form No. 2 format shall apply to reports filed for and covering the 1980 calendar year and each year thereafter.

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[7] In the Notice of Proposed Rulemaking, Form No. 1 changes were slated to become effective for 1980 calendar year reports. Pursuant to requests, however, the Commission has twice extended the comment period on that rulemaking, and has postponed the effective date for any changes to the Form No. 1 until the 1981 reporting year. (*See* 45 F.R. 63296, September 24, 1980, and 45 F.R. 70478, October 17, 1980).

[8] On November 12, 1980, the Commission issued an Order pursuant to a request to permit companies which are required to file both Form Nos. 1 and 2 with the Commission to file the current Form No. 2 for the 1980 reporting year (45 F.R. 76784, November 20, 1980). As mentioned in the text, any revisions to the Form No. 1 filing requirements will not take effect before the 1981 reporting period. This order provides a measure of relief for companies which file both forms since they have the option to submit Form Nos. 1 and 2 in their current formats, for this year's reports, rather than a *revised* Form No. 2 and an *unrevised* Form No. 1.

(Natural Gas Act, as amended, (15 U.S.C. 717–717w); Department of Energy Organization Act, (42 US.C. 7101–7352); E.O. 12009, 3 CFR 142 (1978).)

For the foregoing reasons, Form No. 2 is revised by the Commission as set forth in Attachment C of this Final Rule, and Part 260 of Chapter I, Title 18 of the Code of Federal Regulations is amended by the Commission, as set forth below, effective January 9, 1981.

By the Commission,

Kenneth F. Plumb,
Secretary.

[¶ 30,223]

46 F. R. 6901 (January 22, 1981)

18 CFR Parts 271, 274

[Docket No. RM81–32]

Interim Rule Under Section 108 of the NGPA Concerning Temporary Pressure Buildup in Qualifying Stripper Wells

January 15, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Interim Rule.

SUMMARY: Section 108 of the Natural Gas Policy Act of 1978 (NGPA) establishes a maximum lawful price for natural gas from stripper wells, *i.e.*, wells that produce no more than 60 Mcf of natrual gas per production day during a specified 90 day production period. In this interim rule, the Federal Energy Regulatory Commission (Commission) is amending its regulations implementing section 108 to permit a producer whose well already qualifies for the section 108 stripper well price to continue to charge and collect that price when the well exceeds the 60 Mcf production rate due to pressure buildup during a temporary shut-in of the well. The rule establishes procedures under which a producer may seek a determination by the jurisdictional agency that excess production from a qualified stripper well is the result of a pressure buildup during a temporary shut-in. Such a determination, subject to Commission review, would permit the well to continue to qualify for the section 108 price.

DATES: The interim rule is effective January 15, 1981. Requests for a hearing are due on or before January 30, 1981. A public hearing, if held, will be announced by February 5, 1981. Comments are due on or before 4:30 p.m., February 20, 1981.

ADDRESS: Comments and requests for hearing should be submitted to: Office of the Secretary, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTRACT:

Carol Lane, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Room 4106–G, Washington, D.C. 20426 (202) 357–8317.

Susan Tomasky, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Room 8100, Washington, D.C. 20426 (202) 357–8164

I. Introduction

In Subpart H of its regulations, the Federal Energy Regulatory Commission (Commission) has established rules implementing section 108 of the Natural Gas Policy Act of 1978 (NGPA), which sets a maximum lawful price for natural gas from stripper wells. Generally, the

NGPA defines a stripper well as one that produces no more than an average of 60 Mcf of natural gas per production day in the preceding 90-day production period. The Commission is adopting herein an interim rule amending §§ 271.804, 271.805, 271.806, and 274.206 of its regulations to provide a special rule governing temporary over-production from wells which have previously been determined to qualify as stripper wells.

II. Discussion

Section 108 of the NGPA provides that in order for a well to qualify as a stripper well it must produce an average of 60 Mcf or less of natural gas per production day during the preceding 90-day production period. A well which exceeds the 60 Mcf limit during any 90-day production period loses its stripper well status unless the increased production is shown to be the result of "recognized enhanced recovery techniques." *See* section 108(b)(2).

The Commission has also recognized another situation in which a well may exceed the 60 Mcf per production day limit without losing its stripper well status. Section 271.804(d) of the regulations provides that once a well qualifies as a stripper well, it may retain that status so long as production does not exceed 60 Mcf per production day on a yearly basis, if the well is determined to be "seasonally affected." This "seasonally affected" rule as promulgated in order to allow for cyclical variations in production which result from seasonal pressure differentials on a pipeline system. Without this rule, many stripper wells would have to go through disqualification and requalification procedures each year.

The Commission now finds that there exists another situation that is causing temporary disqualification and subsequent requalification of legitimate stripper wells, placing an undue administrative burden on producers, states, and the Commission. This situation arises when a well is required to be temporarily shut-in to permit, for example, pipeline or wellhead maintenance or repair. During the shut-in days, pressure builds up in the well bore. When the well is reopened to the line, gas is produced at a higher rate of production than that at which the well normally produces, and the shut-in days do not qualify as "production days" for purposes of determining the well's rate of production. (*See* § 271.803(d).) In such situations the well's average rate of production may exceed the 60 Mcf per production day limit for the relevant 90-day production period, and the well may be disqualified as a stripper. As soon as the pressure buildup is dissipated and the well returns to its normal rate of production, the producer must submit a new application for a determination that the well is a stripper well, file a Form 121, fulfill the interim collection filing requirements[1] and comply with all of the other requirements necessary to receive a well category determination and collect the maximum lawful price under the category.

The Commission believes that once a well has been determined to be a stripper well, short-term over-production resulting from temporary pressure buildups such as those described above should not cause the well to lose its legitimate stripper status. The Commission further believes that it is within the spirit and intent of section 108 to encourage continued production from marginal wells by removing undue administrative burdens which may result when a stripper well is disqualified as a result of temporary pressure buildup. Accordingly, the Commission is acting under its administrative and rulemaking authority set forth in section 501(a) of the NGPA to promulgate a rule that will provide for continuing qualification of stripper wells that experience temporary pressure buildups.

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[1] Recently adopted modifications to the interim collection filing requirements applicable for stripper wells are set out fully in the Final Rule in Docket No. RM80-54, Amendment to Part 273 Regulations Under the Natural Gas Policy Act.

III. Summary of Regulations

Section 271.804 (Special rules) is being amended to add a rule which provides that a previously qualifying stripper well that produces gas in excess of an average of 60 Mcf per production day during any 90-day production period shall not be disqualified from stripper status if the jurisdictional agency finds that:

(A) The rate of production in excess of 60 Mcf per production day resulted solely from pressure buildup when the well was temporarily closed to the line;

(B) Total production for the relevant 90-day production period did not exceed 5400 Mcf;[2] and

(C) The well would have produced at a rate not exceeding 60 Mcf per production day during the relevant 90-day production period had the well been continuously open to the line during that period.

Section 271.805 is amended to provide that if a well's production exceeds the 60 Mcf limit for any 90-day production period, the well operator may file with the jurisdictional agency a petition for a determination that the increased production is the result of temporary pressure buildup. The jurisdictional agency shall then make an affirmative or negative finding on the petition and forward such finding to the Commission for review. Sections 271.806 and 274.206 are amended to conform to this procedure.

IV. Effective Date

This interim rule relieves restrictions previously placed on applicants under the Commission's regulations. Accordingly, it is being made effective immediately. This rule shall not become final, however, until the Commission has had an opportunity to receive oral and written presentation of relevant data, views and arguments.

V. Public Procedure

A. Written Comments

Interested persons are invited to submit comments, data, views, or arguments with respect to this interim regulation. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, and should refer to Docket No. RM81-12. An original and 14 copies should be filed. All comments received prior to 4:30 p.m., February 20, 1981, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the public file that has been established in this docket. This file is available for public inspection in the Commission's Division of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C., during regular business hours.

B. Public Hearing

Interested persons may request the opportunity for an oral presentation of their views at a public hearing. Requests for a hearing should be submitted no later than January 30, 1981, to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, and should reference Docket No. RM81-12. If a public hearing is held in this docket, the time and place will be announced by February 5, 1981.

(Natural Gas Policy Act of 1978, (15 U.S.C. 3301-3432); Department of Energy Organization Act, (42 U.S.C. 7101, *et seq.*); E.O. 12009, 42 FR 46267)

In consideration of the foregoing, the Commission amends Subpart H, Chapter I, Title 18, Code of Federal Regulations, on an interim basis, as set forth below, effective immediately.

By the Commission.

Lois D. Cashell,
Acting Secretary.

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[2] The 5400 Mcf figure has been selected because it represents the maximum amount of gas that can be produced from a well during a 90-day production period if that well is to maintain its stripper well status, *i.e.*, 60 Mcf per day × 90 days = 5400 Mcf.

[¶ 30,224]

46 F. R. 9027 (January 28, 1981)

18 CFR Parts 4, 131

[Docket No. RM81-11; Order No. 123]

Procedures and Corrected Revision to Regulation Governing Preliminary Permits and Licenses

January 21, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission adopts procedural and correctional revisions to the regulations governing preliminary permits and licenses. The revisions are designed to clarify and correct the Commission's regulations in order to eliminate confusion relating to the status of competing applications, the data requirements of an application, and certain perceived inconsistencies in the regulations.

EFFECTIVE DATE: February 27, 1981.

FOR FURTHER INFORMATION CONTACT:

Ronald Corso, Office of Electric Power Regulation, Federal Energy Regulatory Commission, 825 N. Capitol Street, N.E., Washington, D.C. 20426, 202-376-9171.

Phillip Leber, Office of the General Counsel, Federal Energy Regulatory Commission, 825 N. Capitol Street, N.E., Washington, D.C. 20426, 202-357-5514

James Hoecker, Office of the General Counsel, Federal Energy Regulatory Commission, 825 N. Capitol Street, N.E., Washington, D.C. 20426, 202-357-9342

The Federal Energy Regulatory Commission (Commission) establishes certain procedural and correctional revisions to the regulations governing preliminary permits and licenses. The rule amends §§ 4.31, 4.33, 4.51, 4.81, 4.92, 131.3, and 131.4 and is effective 30 days after publication.

I. Background

The Commission has recently completed several revisions of its regulations to simplify and expedite hydropower licensing.[1] In conjunction with these rulemakings, several procedural and correctional changes are necessary to clarify and correct the Commission's regulations governing preliminary permits and licenses.

The revisions in this rulemaking have three primary objectives: (1) To eliminate confusion relating to the status of competing applications for preliminary permit; (2) to clarify the data requirements contained in certain regulations; and (3) to eliminate perceived inconsistencies in the regulations.

II. Section by Section Summary of the Revisions

Section 4.31(b)

The Commission has determined that fourteen copies, rather than the currently required ten copies, of each preliminary permit and license application are necessary to enable adequate and timely review of the proposed project plans by staff.

Section 4.31(d)

There has been a substantial amount of confusion relating to the difference in the treatment accorded "deficient" and "patently deficient" applications. The language of the existing regulations does not clearly explain the intent of the rule as written and presently administered. Some applicants have read this section and assumed incorrectly that, if a rejected application is corrected within 45 days, the corrected application will be deemed accepted for filing on the original filing date, and that the application will be considered pending during the 45-day period. This revision states that the acceptance date of any rejected application will be the date of resubmittal. The substantive requirement upon which these revisions are based may be found in §§ 1.14 and 4.33(d)(2).

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[1] *See* Commission Order No. 11, "Regulations Governing Applications for Short-Form License (Minor)" (Docket No. RM78-9), issued September 5, 1978, 43 FR 40215, September 11, 1978; Order No. 54, "Regulations Prescribing General Provisions for Preliminary Permit and License Applications; and Regulations Governing Applications for Amendments to and Cancellation of Permits" (Docket No. RM79-23), issued October 22, 1979, 44 FR 61328, October 25, 1979; Order No. 59, "Regulations Governing Applications for License for Major Projects—Existing Dams" (Docket No. RM79-36), issued December 16, 1979, 45 FR 75383, December 20, 1979; Order No. 76, "Exemption of Small Conduit Hydroelectric Facilities from Part I of the Federal Power Act" (Docket No. RM79-35), issued April 18, 1980, 45 FR 28085, April 28, 1980; and Order No. 106, "Exemption from All or Part of Part I of the Federal Power Act of Small Hydroelectric Power Projects with an Installed Capacity of 5 Megawatts or Less" (Docket No. RM80-65), issued November 7, 1980, 45 FR 76115, November 18, 1980.

Sections 4.33(b)(1) and 4.81(a)(3)

These revisions require the applicant to provide its telephone number in addition to its name and business address.

Section 4.33(d)(2)

Applicants have questioned the nature of the requirement to show how the plans of a competing application are as well adapted or better adapted than is the initial application to develop, conserve, and utilize the water resources of the region. This revision explains that it is appropriate, but not mandatory, to support the statement with a technical analysis. Technical analysis will assist the Commission in making decisions regarding competing applications, and this revision makes it clear that the Commission will accept such information as part of the application.

Sections 4.51(a)(6) and 4.81(a)(6)

These revisions add the requirement that the applicant furnish the name and address of the owner of water power facilities, and if the dam is Federally owned or operated, the applicant must provide the name of the agency involved. This information will facilitate the Commission's giving adequate notice to dam owners of pending preliminary permit or license applications filed by non-owners.

Section 4.51(f)(6)(ii)

The existing regulations erroneously cited the Federal Power Commission Reports as "CFR". This revision corrects the citation to read "F.P.C.".

Section 4.51(g)

The present Exhibit F for all major projects requires a number of voluminous technical reports that are required for staff review of the proposed project only. This section is revised to require that the technical information used as a basis for the design of the project be compiled into one report and submitted at the time the design drawings are submitted to the Commission for review. Only five copies of this report, rather than the standard fourteen copies, must be included as part of the application.

Section 4.81(b)(4)

The current Exhibit 1 requires that the applicant provide an estimate of the energy output and installed capacity of the proposed project. Many applicants do not state these data with specificity. This revision clarifies the requirements of Exhibit 1 by specifying that information must be provided detailing the average annual energy production, installed capacity, hydraulic head, and data concerning any turbines and generators proposed by the applicant.

Section 4.81(d)(3)

This subparagraph clarifies the existing requirement for general information on the proposed market for the project's output. Either the identity of the proposed purchaser(s) and the anticipated revenues must be provided, or, if the applicant proposes to use the power, the size of the system, peak demand and annual energy requirements, and the number of customers served by the applicant's proposed project must be supplied.

Section 4.81(e)(3)(i)

Many applications for preliminary permit are deficient because the project map does not show all project features within the proposed project boundary. Furthermore, in those cases where a Federal dam is involved, many applicants are unclear about the need to show the Federal project in relation to other non-Federal project features. This revision clarifies the requirements by specifying certain elements that must be included within the project boundary, and by indicating that only the power plant is required to be shown within the project boundary when the project is at an existing Federal dam.

Section 4.92(c)(5)(iv)

This change clarifies the applicant's responsibilities in the pre-application consultation process. The applicant is required to consult with appropriate resource agencies and submit documentation or a summary of the consultation process with its application for exemption. The applicant must allow at least 30 days for each agency consulted to respond.

Section 131.3

Section 131.3, which prescribes the form for certification of organization, is revoked. Through numerous previous rulemakings, all references to this section have been eliminated.

Section 131.4

Section 131.4, which prescribes the form for certification of exhibits, is revoked. Through numerous previous rulemakings, all references to this section have been eliminated.

III. Notice and Effective Date

The Commission finds that a general notice of proposed rulemaking need not be published in the **Federal Register** because the rule is clarifying and corrective and is basically one of agency procedure and practice.[2]

(Federal Power Act, as amended, (16 U.S.C. 792–828c); Public Utility Regulatory Policies Act of 1978, (16 U.S.C. 2601–2645); and the Department of Energy Organization Act, (42 U.S.C. 7101–7352); E.O. 12009, 3 CFR 142 (1978)).

In consideration of the foregoing, the Commission amends Parts 4 and 131 of Chapter I, Title 18, Code of Federal Regulations, as set forth below, effective on or before Febuary 27, 1981.

By the Commission.

Lois D. Cashell,
Acting Secretary.

[¶ 30,225]

46 F. R. 9029 (January 28, 1981); 46 F. R. 11811 (February 11, 1981)

18 CFR Part 12

[Docket No. RM80-31; Order No. 122]

Water Power Projects and Project Works Safety

Issued: January 21, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) hereby adopts a Final Rule Governing the Safety of Water Power Projects and Project Works. The rule consolidates the Commission's orders, regulations, and practices relating to project safety under Part 12 of the Commission's rules. The rulemaking applies to all water power projects and project works licensed or required to be licensed under Part I of the Federal Power Act. The rule may also be made applicable to some projects exempted from licensing, pursuant to Subparts J or K of the Commission's rules by means of conditions of exemption.

EFFECTIVE DATE: March 1, 1981.

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[2] *See* 5 U.S.C. 553(b)(3)(A) [Administrative Procedures Act].

FOR FURTHER INFORMATION CONTACT:

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Order No. 122—Final Rule

Before Commissioners: Georgiana Sheldon, Acting Chairman; Matthew Holden, Jr., George R. Hall and J. David Hughes. Regulations Governing Safety of Water Power Projects and Project Works.

The Federal Energy Regulatory Commission (Commission) gives notice that it adopts a final rulemaking governing the safety of all water power projects and project works [1] licensed or required to be licensed under Part I of the Federal Power Act (Act). The rules may also be made applicable to some projects exempted from licensing, pursuant to Subparts J or K of the Commission's rules, by means of conditions of exemption. The rulemaking consolidates the Commission's orders, regulations, and practices relating to project safety under Part 12 of the Commission's rules.

I. Background

The Federal Energy Regulatory Commission licenses water power projects that are developed by non-Federal entities including individuals, private entities, states, municipalities, electric cooperatives, and others. At the end of 1979, the Commission had under its jurisdiction 1,144 dams of all sizes and hazard classifications, including those for which applications for license were pending.

Under section 10(c) of the Act, the licensee of any water power project within the jurisdiction of the Commission must conform to any rules that the Commission "may from time to time prescribe for the protection of life, health, and property." [2] In addressing its responsibility under section 10(c) of the Act the Commission has developed procedures to ensure quality in design, construction, operation, and maintenance of water power projects.

The Commission staff reviews designs before the construction of licensed projects. During the construction of a project, the regional offices conduct periodic inspections, usually monthly. Furthermore, the Commission often requires, in the terms and conditions of a license for an unconstructed project, that the licensee appoint a board of independent consultants subject to the Commission's approval. The board acts in an advisory capacity during the construction of the project. Once a water power project becomes operational, members of the Commission staff conduct an annual review of the project's operating history and compliance with licensing conditions, and inspect the project works.

The Commission also requires for all licensed projects, and any project for which a license application is pending or has been found to be required the implementation, and modification when appropriate, of an emergency action plan. The plan must be designed to provide an early warning to upstream and downstream inhabitants, property owners, recreational users and public safety agencies in case of an impending or actual sudden release of water caused by an accident to or failure of any project structure.

On December 27, 1965, the Commission's predecessor agency, the Federal Power Commission (FPC), provided in Order No. 315 [3] for complete safety inspections of licensed water power project works by independent consultants at five-year intervals, or more frequently if necessary. The existing Part 12 regulations under FPC Order No. 315 are applicable only to those licensed projects that have a dam exceeding 35 feet in height above the streambed or a gross storage capacity of more than 2,000 acre-feet. The inspection provisions established by Order No. 315 were designed to supplement the staff's inspection of all project works with detailed periodic safety inspections supervised by an independent consultant.

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[1] The terms "project" and "project works" have the same meaning as defined in section 3(11) and section 3(12) of the Federal Power Act.

[2] 16 U.S.C. 803(c) (1976).

Dam failures in the 1970's, notably the failure of Teton Dam (U.S. Department of the Interior, Water and Power Resources Service), and the Taccoa Falls Dam in Georgia, demonstrated a need to review Federal and non-Federal dam safety practices and procedures. Pursuant to President Carter's directive on April 23, 1977, Federal review was initiated by several Federal agencies to ensure the structural integrity of project works and to establish well-conceived plans to protect life and property if an emergency should occur as a result of a dam failure or accident causing a sudden release of water.[4]

The Commission had already begun extensive review of its project safety policies and procedures at the time of the Walter Bouldin Dam failure on February 10, 1975 (FERC Project No. 2146). Dam safety inspections were a standard part of the Commission's program at the time. However, during the period of review the Commission determined that it was advisable to consolidate the various regulations, orders, and practices relating to project safety in the Commission's regulations.

On June 16, 1980, the Commission issued a Notice of Proposed Rulemaking (NOPR) [5] in this docket which consolidated under Part 12 those portions of the current project safety program that were initiated by case-specific Commission orders and revised the existing project safety inspection regulations. The Commission received 75 written comments on the NOPR and has considered all comments in the formulation of the final rule.

II. Section-By-Section Analysis

Subpart A—General Provisions.

The rulemaking revokes the existing dam inspection procedures in Part 12 of the Commission's rules and replaces them with new practices and procedures that encompass safety inspections by independent consultants and other aspects of the Commission's project safety program not previously included in Part 12.

§ *12.1 Applicability.*

Paragraph (a) provides that this part applies to water power projects licensed under Part I of the Federal Power Act (Act), and to any unlicensed constructed project for which the Commission has determined that an application for license must be filed.

Contrary to the positions of some commenters, the Commission has adequate authority under Section 4(g) of the Act to make its safety regulations apply to unlicensed constructed projects that it has determined must be licensed.

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[3] Inspection of project works with respect to safety of structures, 18 CFR Part 12 (1980).

[4] According to the President's directive, the Chairman of the Federal Coordinating Council for Science, Engineering and Technology (FCCSET) was to preside over the preparation of Federal dam safety guidelines. The Director of the Office of Science and Technology Policy (OSTP) would then establish a committee of experts to review the proposed procedures and policies. Three significant documents have been produced through the interagency review of dam safety practices initiated by the President in 1977. In November 1977, FCCSET issued a report entitled Improving Federal Dam Safety, followed by the Federal Dam Safety Report of the OSTP Independent Review Panel in December 1978. FCCSET published its Federal Guidelines for Dam Safety on June 25, 1979. Finally, the President requested that each department and agency report to the Director of the Federal Emergency Management Agency (FEMA) concerning the progress made toward implementing the guidelines. The Chairman of the FERC transmitted the Commission staff's report to FEMA on February 1, 1980. The FERC report showed substantial prior compliance with the guidelines.

[5] 45 FR 41606 (June 19, 1980).

In light of the Commission's rulemaking allowing certain hydro facilities of 5 megawatts or less capacity to gain exemption from licensing (among other things),[6] the Commission has amended paragraph (a) by adding a new subparagraph (3). Subparagraph (a)(3) includes such facilities within the Applicability section, to the extent that conditions of exemption subject a project to the provisions of these rules.

Furthermore, the Commission has clarified, by adding a new paragraph (b), the applicability of this section to projects located at federal dams. The rule does not apply to federal dams themselves, but does apply to hydroelectric facilities licensed by the Commission that are located at federal dams.

§ *12.2 Rules of construction.*

Paragraph (a) indicates that the provisions of this rule normally apply rather than any similar term or condition of a license. In the NOPR the Commission proposed requiring that the licensee comply with the stricter of two similar provisions located in a license and this part.

Several commenters suggested that the Commission delete that provision. Under Section 10(c) of the Act, the Commission clearly has authority to impose conditions in its safety regulations stricter than those required in a license. For greater certainty, some commenters suggested that this provision be revised to require that the licensee always comply with the provisions of a license unless the provisions in this rule would significantly contribute to the safe operation and condition of the project. The Commission has revised the rule to provide more certainty. In the interests of unformity, however, it is preferable that all projects conform to the provisions of these regulations unless terms of a particular project's license would better protect life, health, or property. The Commission has revised paragraph (a) accordingly.

Paragraph (b) provides for advisory rulings by the Director of the Office of Electric Power Regulation with regard to the requirements of paragraph (a) above.

§ *12.3 Definitions.*

This section contains definitions applicable to this part of the Commission's rules. Paragraph (a) provides that for purposes of this part terms defined in section 3 of the Federal Power Act have the same meaning as they have under the Act.

Subparagraph (1) defines an "applicant" to mean any person, state, or municipality that has applied for a license for an unlicensed, constructed project and any owner of an unlicensed, constructed project for which the Commission has determined that an application for license must be filed. The Commission has added "state or municipality" to the definition of applicant to clarify the applicability of this rule to such entities.

Several commenters questioned the basis for the Commission's jurisdiction over unlicensed, constructed projects for which the Commission has determined that an application for license must be filed. As noted above, the Commission's jurisdiction in this case is derived from section 4(g) of the Act. Therefore, the Commission has not changed the definition of "applicant," which includes owners of certain unlicensed, constructed projects. A definition of "owner" has been added in subparagraph (2) to provide clarification to the definition of "applicant."

Subparagraph (3) of the proposed rule defined "authorized Commission representative" as the Director of the Office of Electric Power Regulation, the Director of the Division of Hydropower Licensing, the Regional Engineer, any person specifically authorized by one of those officials to act in his or her stead, or any other member of the Commission staff whom the Commission may designate. In response to comments noting that licensees should be assured that enforcement will be by experienced officials appointed by the Commission, the Commission has amended the definition by deleting the phrase "any person specifically authorized by one of these officials to act in his or her stead."

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[6] 45 FR 76115 (November 18, 1980).

In the proposed rule, subparagraph (4) defined "condition affecting the safety or adequacy of a project or project works" to mean any condition, event, or action at the project which might compromise the safety, stability, or integrity of any project work with respect to its continuing ability to protect life, health, or property or to protect the water resources of the region for navigation, water power development, or other beneficial public uses including recreation, or otherwise adversely affect life, health, or property. The definition provided several examples of conditions that might affect the safety of a water power project or the project works.

Several commenters suggested that section 10(c) of the Act does not authorize the Commission to prescribe regulations encompassing non-safety related factors. Section 10(c) of the Act requires a licensee to "conform to such rules and regulations as the Commission may from time to time prescribe for the protection of life, health, and property." In the final rule, the Commission has deleted all references to the "adequacy" of a project or project works in response to comments about ambiguity of the term in context. In addition, the Commission further revised the definition to clarify that these conditions are safety-related.

A number of commenters also objected to the "might compromise" standard in this definition. The proposed substitution of a "would compromise" standard would leave too much room for argument over potentially critical safety matters. These rules retain the proposed language so that even if the licensee has some doubt, in cases where it is possible that safety is endangered, reporting will be required and other steps may be taken as advisable.

In response to the comments, several modifications have been made to the non-exclusive list of examples of conditions that affect the safety of a project or projects works. Section 12.3(b)(4)(ii) has been clarified and § 12.3(b)(4)(v) has been divided, thus creating a new subsection (vi), for clarification purposes.

Subparagraph (5) defines "constructed project" to mean any project with an existing dam.

Subparagraph (6) defines "dam" to mean any structure for impounding or diverting water.

Subparagraph (7) defines "development" to mean that part of a project comprising an impoundment and its associated dams, forbays, water conveyance facilities, a power plant, and other appurtenant facilities. A project may be comprised of one or more developments.

Several commenters suggested that the term "modification" as used in the proposed rule was ambiguous and should be defined. The Commission has added a new subparagraph (8) which defines "modification" to mean any activity, including repair or reconstruction, that in any way changes the physical state of any project work or any other physical feature of the project from the state reflected in the plans, drawings, or other documents filed with the Commission.

Subparagraph (9) defines "project emergency" to mean an impending or actual sudden release of water at the project caused by natural disaster, accident, or failure of project works.

Subparagraph (10) defines "Regional Engineer" as the person in charge of the Commission's regional office for the region (Atlanta, Chicago, Fort Worth, New York, or San Francisco) where a particular project is located.

§ 12.4 *Staff administrative responsibility and supervisory authority.*

Paragraph (a) explains that the chief administrator of the Commission's project safety program is the Director of the Office of Electric Power Regulation

(OEPR). The Director OEPR reports directly to the Chairman of the Federal Energy Regulatory Commission.

Paragraph (b) sets forth with specificity the authority of the Regional Engineer or other authorized Commission representative to inspect and supervise the construction, operation, maintenance, use, or modification of any project works. Commenters questioned the breadth of the supervisory authority under this section. The Commission believes that standard articles placed in new licenses have given the Regional Engineer even broader general supervisory powers over the construction, operation, and maintenance of a project.

In order to clarify the intent of these regulations, however, the Commission has amended paragraph (b) to specify that the supervision and inspection authority granted under this paragraph relates to project safety. The Regional Engineer or any other Commission representative is authorized to test or inspect any project works or to require the licensee to do so; to require a licensee to submit certain reports or information; to require a licensee to modify emergency action plans or any plan for corrective measures; to take any preventative or corrective measures; and to prescribe a time for performing these actions.

Commenters questioned the part of the regulations that explains that an order or directive or a Regional Engineer or other authorized representative is immediately effective and remains in effect until stayed. The Commission believes that this part reflects the usual provisions for the effective dates of orders [7] and stays [8] and the fact that the Commission's representative is acting in the Commission's stead.

The time when an order is effective, however, should not be confused with the time when a licensee might be required to take a particular action, which would be specified in the order. Moreover, the importance of the Regional Engineer's orders being immediately effective to carry out the purposes of section 10(c) of the Act is clear. In safety emergencies it would be impracticable to hold action in abeyance while the merits of the situation were presented for Commission deliberation. The Regional Engineer, with much more intimate day-to-day knowledge and experience on a project must be in a position to require prompt remedial action.

In response to the comments received, the Commission has modified the provisions of paragraph (c) to provide additional clarification. The new provisions specifies that either the Regional Engineer or other authorized Commission represetative who issued an order or directive under this section, or the Commission, may rescind or amend that order or directive, in addition to staying its effect for a particular period. The rules also make clear that any orders or directives by the Regional Engineer or other authorized Commission representative pursuant to § 12.4(b) or Subparts B through E of Part 12 are subject to appeal under the provisions of § 1.7(d) of the Commission's rules.

§ 12.5 Responsibilities of licensee or applicant.

Section 12.5 sets forth the general standard that a licensee or applicant must use sound and prudent engineering practices in designing, constructing, operating, maintaining, using, or modifying a water power project or project works. As noted in the NOPR, it is primarily the licensee's responsibility to protect life, health, and property.

Subpart B—Reports and Records

§ 12.10 Reporting safety-related incidents.

Paragraph (a) requires an applicant or licensee to report to the Commission orally and in writing any condition affecting the safety of the water power project or the project works. This paragraph specifies the information that the Regional Engineer may require.

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[7] *See* 18 CFR 1.13(c) (1980).

[8] *See* Section 313(a) of the Act.

Paragraph (b) requires the applicant or licensee to report any deaths or serious injuries that occur at, or are attributable to, the water power project. This report must be made promptly after the applicant or licensee becomes aware of the incident.

§ *12.11 Reporting modifications of the project or project works.*

Paragraph (a) requires the reporting of project modifications to the Regional Engineer. Many commenters suggested that the requirement that "any modification" be reported was vague. The Commission believes that the new definition of "modification" added to § 12.3 will clarify this provision. Furthermore, the time for reporting non-emergency modifications established in paragraph (b) has been increased from 15 to 60 days before the work begins.

§ *12.12 Maintenance of records.*

Paragraph (a) specifies the kinds of records that must be maintained by the applicant or licensee and the appropriate locations to maintain both permanent original project records and copies of such records. A provision is included in paragraph (c) to provide for the transfer of permanent project records to a successor licensee or the government if ownership of the project changes.

The Commission has also clarified that where project records are not available and could not reasonably have been acquired when the licensee acquired the project, they need not be reconstructed.

Many commenters suggested that copies of all permanent projects records are not needed at the project site, so long as originals are securely maintained at a central location. The Commission adopts this suggestion and has amended paragraph (b)(2) accordingly so that not all permanent records must be maintained at the project site. If the licensee or applicant maintains permanent project records at a central location other than the project site, they must only maintain at the project site the basic design drawings, instrumentation data, and operational history that are necessary for the safe and efficient operation of the project.

Furthermore, the Commission has added a new subparagraph (3) that allows the licensee or applicant to maintain microfilm or microfiche of records if the appropriate viewing equipment is available subject to the provisions of Part 125 of the reguations.

§ *12.13 Verification form.*

Section 12.13 has been added to the final rule as an example of the verification which is required under several sections of the rule.

Subpart C—Emergency Action Plans

§ *12.20 General requirements.*

This subpart constitutes a major element of the Commission's project safety procedures. Paragraph (a) requires an applicant or licensee to file three copies of an emergency action plan with the Regional Engineer. The plan must make provision for measures to be taken during a project emergency, including failure of the dam.

Paragraph (b) requires emergency action plans to be developed by an applicant or licensee in coordination with Federal, state, and local agencies. The plan must be designed to provide early warning to upstream and downstream inhabitants, property owners, operators of water-related facilities, recreational users, and other persons in the vicinity who might be affected by a project emergency.

§ *12.21 Exemptions.*

As proposed, paragraph (a) allowed the Director of the Office of Electric Power Regulation or the Regional Engineer to grant an exemption from the general requirements stated above if the applicant or licensee could demonstrate that "no project emergency would endanger life, health or property." In response to several comments, the Commission has amended paragraph (a). In order to obtain exemption from the requirements of filing an emergency action plan, an applicant or licensee must demonstrate that "no reasonably foreseeable project emergency would endanger life, health, or property." Upon such a showing the Regional Engineer may grant exemption from the filing requirement.

Paragraph (b) prohibits exemptions from the requirements of § 12.22(c) for a radiological response plan.

Paragraph (c) provides that an exemption from the requirement of this subpart is not perpetual, and the applicant or licensee is charged with the responsibility of reviewing conditions upstream and downstream from the project to ascertain whether an emergency action plan would be advisable. The Commission believes that an annual review is appropriate as a minimum, given the potential for harm involved.

Paragraph (d) provides that an exemption may be revoked if conditions change significantly.

§ *12.22 Contents of an emergency action plan.*

Paragraph (a) prescribes the contents of an emergency action plan. The plan must be filed in accordance with the Guidelines For Preparation of Emergency Action Plans established by the Director of OEPR and set forth in the Appendix. The plan must take into account the time of day, in particular the occurrence of a project emergency during hours of darkness.

In response to several comments, the Commission has reorganized the general requirements of the emergency action plan. The Commission believes that the actual plan which is posted or given to operating personnel to instruct them on procedures during an emergency should be as brief and simple as possible. Training plans and the studies and other information supporting a particular plan are important appendices to be filed with the Regional Engineer, but are inappropriate to the body of the plan itself.

Accordingly, in paragraph (a) the Commission requires three ingredients within the body of the plan itself. The body of the plan must include: Emergency action instructions to key project personnel; detailed plans for notifying affected persons and appropriate Federal, state and local agencies, and procedures for controlling the flow of water. Study summaries and training plans are to be included in the emergency action plan appendices submitted to the Regional Engineer.

Paragraph (c) requires the applicant or licensee to file a radiological response plan if an operator of a project powerhouse or water storage and release control facilities would be located within ten miles of a nuclear power plant reactor. The plan must provide for emergency procedures in the event of an accident or incident at the nuclear power plant reactor that results in the release of radioactivity into the air or water. The objective of the plan is to provide for the possibility of short-term abandonment of the project works, effective control of stream flows, and contingency arrangements for continuing, curtailing, or ceasing power generation. A project which is otherwise exempted from the requirement to file an emergency action plan must still file a radiological response plan.

§ *12.23 Time for filing emergency action plan.*

This section prescribes the deadlines for filing the emergency action plans for all projects. In response to comments regarding paragraph (a), unconstructed projects, the Commission has increased the time for filing an emergency action plan from 30 days to 60 days before the initial filling of the project reservoir. Furthermore, the filing of an emergency action plan is required 60 days prior to commencement of construction where a temporary construction impoundment would be created if an accident or failure of the impounding structure would endanger public health and safety. For example, the construction of a temporary or permanent cofferdam or a large sediment control structure may require the filing of an emergency action plan with regard to these structures prior to their construction. A plan filed with regard to such construction may require modificiation before the initial filling of the project reservoir begins, in order to provide for adequate protection under the changed circumstances.

Paragraph (b) and (c) provide the time of filing emergency action plans for unlicensed constructed projects and licensed constructed projects respectively.

A new subparagraph (d) has been added that allows the Regional Engineer, for good cause shown, to grant an extension of time for filing all or any part of an emergency action plan.

§ *12.24 Review and updating of plans.*

In light of several comments, the Commission has modified this section by adding a new paragraph (a) that requires continual updating of the plan to reflect changes in personnel, telephone call numbers, and other similar information in the plan. The intent is to ensure that, in time of an emergency, project personnel are not confronted with stale information regarding who is responsible for what, whom to notify, and how to notify them.

Paragraph (b) requires that emergency action plans must be comprehensively reviewed by the applicant or licensee at least once a year and updated to ensure adequate protection for life, health, or property affected by the project. Moreover, the applicant or licensee is required to review the adequacy of the plan in light of any significant changes upstream or downstream of an impoundment and to promptly file with the Regional Engineer any modifications of the plan which result from such changes.

§ *12.25 Posting and readiness.*

Paragraph (a) requires a licensee or applicant to post the current emergency action plan. The posting must be in a prominent location so that it is readily accessible to the applicant's or licensee's operating personnel who are responsible for taking emergency action.

Paragraph (b) continues to require the licensee or applicant to test the readiness of key licensee or applicant personnel for an emergency situation. The Commission has retained the requirement that the applicant or licensee conduct a test, and not merely a review, of key personnel. The Commission anticipates that such a test would include a drill simulating actual emergency conditions.

Subpart D—Inspection by Independent Consultants

This subpart is a revision of the Part 12 requirements in the existing regulations. While this subpart continues to prescribe initial inspections and subsequent five-year inspections by independent consultants, it will require inspection of a larger number of project developments.

§ *12.30 Applicability*

Paragraph (a) indicates that this subpart applies to any licensed project development that has a dam: that is more than 32.8 feet (10 meters) in height above streambed; or that impounds an impoundment with a gross storage capacity of more than 2,000 acre-feet (2.5 million cubic meters); or that has a high hazard potential. Formerly, inspections by independent consultants were performed only on those dams more than thirty-five feet in height or impounding more than 2,000 acre-feet of water. The revised inspection requirements add to this category of dams any dam with a high hazard potential, as defined in § 12.31(b), that the Regional Engineer determines requires an inspection. This requirement recognizes that the need for stringent measures to protect life, health, or property may depend on the location and other characteristics of a project development relative to certain geographic, demographic and economic features of the vicinity.

§ *12.31 Definitions*

This section supplies additional definitions for this subpart. Many of the commentors objected to the requirement in the proposed rule that an independent consultant not have had substantial responsibility for the design, construction, or maintenance of the project under inspection for 10 years, except as an independent consultant. The Commission has carefully weighed the competing consideration in this matter. The Commission has concluded that the possibility that the proposed rule might unduly restrict the availability of competent independent consultants appears, at this time, to outweigh the potential for conflicts of interest or other difficulties that might flow from removing the restriction.

The definition of "independent consultant" has, therefore, been modified in paragraph (a) and means a person that is not, and has not been within two years of being retained to perform an inspection under this subpart, an employee or agent of the licensee or its affiliates. In addition, an independent consultant must be a licensed professional engineer and must have at least 10 years of experience and expertise in dam design and construction, and in the investigation of the safety of existing dams. The Commission notes that the requirement that an independent consultant have 10 years of experience does not preclude other consultants with less experience from working on an inspection under the direction and supervision of an independent consultant. Qualification requirements for an independent consultant are subject to approval by the Director of the Office of Electric Power Regulation prior to the initiation of an inspection under § 12.31. Paragraph (e) establishes that the Director of the Office of Electric Power Regulation also has the authority to waive the 10-year requirement in subparagraph (a)(2) for good cause.

The proposed rule defined "dam that has a high hazard potential" as any dam whose failure, in the judgment of the Regional Engineer, the Commission, or its authorized representative, might present a significant risk of endangering human life or causing significant property damage, or which meets the criteria for high hazard potential as defined by the Corps of Engineers in 33 CFR Part 222, Table 2. The Commission has retained the definition as initially proposed except in the final rule the reference to Table 2 of 33 CFR Part 222 has been deleted. The Corps' criteria for high hazard potential are to be determined by an examination of 33 CFR Part 222 generally and not solely with reference to Table 2.

Paragraph (c) defines "height above streambed" and paragraph (d) defines "gross storage capacity."

§ 12.32 *General requirements.*

This section provides the general requirement that the project works of each development within the scope of this subpart must be inspected by a qualified independent consultant in order to identify any actual or potential deficiencies in the project or its works. Several commenters were confused as to whether a consulting firm could perform the inspection. In fact the Commission would presume that this would be the case in most instances, and only requires that the inspection be done under the direction and supervision of an independent consultant. Accordingly, the Commission has revised the rules to clarify that an independent consultant who is a member of a consulting firm may perform the inspection.

§ 12.33 *Exemption.*

Section 12.33 provides for exemption from the requirements of this subpart.

§ 12.34 *Approval of consultant.*

This provision has been added to provide for review and approval of the independent consultant by the Director of the Office of Electric Power Regulation before the inspection begins.

§ 12.35 *Specific inspection requirements.*

Section 12.35 prescribes the scope of the periodic inspections by an independent consultant. Paragraph (a) and (b) provide that the inspection must include a review of all relevant reports, a physical field inspection, and an evaluation of certain project features.

As initially proposed, paragraph (c) required the independent consultant to use any special equipment, instrumentation, or personnel as may prudently be necessary. Several commenters indicated that such requirements are not generally employed in a periodic safety inspection. Moreover, it was pointed out that any such requirement that may prudently be necessary will be employed by the independent consultant in the exercise of his professional judgment. The Commission believes that the inclusion of this requirement was either unnecessary or redundant. Accordingly, paragraph (c) has been deleted from the final rule.

§ *12.36 Emergency corrective measures.*

Section 12.36 requires that, if the independent consultant discovers any condition that may necessitate emergency corrective measures, the consultant must report such a condition to the licensee. The licensee must then notify the Regional Engineer. The notification to the Regional Engineer is to be made pursuant to the provisions of §12.10(a).

§ *12.37 Report of the independent consultant.*

Paragraph (a) contains the general requirement that, following the inspection of a project development by an independent consultant, a report of the inspection must be made to the licensee. The licensee must then file three copies of that report with the Regional Engineer.

Paragraph (b) explains what general information must be included in the initial report that an independent consultant must prepare and file pursuant to an inspection under this subpart. Subparagraph (2) permits incorporation by reference of materials found in certain earlier inspection reports.

Paragraph (c) sets forth the kinds of data and information that must be provided in all reports, the general nature of the analyses to be performed. and an outline of the nature of the recommendations a consultant must make. If any consultant involved in the project inspection dissents from the major recommendations of report, the dissenting views must be included in the report. Furthermore, any changes in information required under this section occurring after it has been initially reported must be included in subsequent reports.

As initially proposed, subparagraph (c)(1) required the report to contain monitoring information that includes specified time-versus-reading graphs. In response to several comments, the Commission has modified this provision to make it clear that reports need only include monitoring information from instrumentation which is already in place; it does not require installation of instruments not otherwise installed or required to be installed.

Furthermore, the Commission has added a new subparagraph (c)(3) under which the report may include an appropriate reference to previous reports in lieu of the required evaluation if conditions and assumptions have not changed since the last report. In the appropriate circumstances, this provision will help the independent consultant avoid needless duplication of information and analyses.

In response to comments that the required list of participants was too broad, the Commission has also modified subparagraph (c)(5). In the proposed rule, it was required that the report identify "all persons who participated" in the project inspection or the report preparation. The final rule makes clear that only a list of professional personnel and the independent consultants is required.

§ *12.38 Time for inspections and reports.*

Section 12.38 provides the timing of the periodic inspections by an independent consultant. Paragraph (a) requires that the project works of any development must undergo inspections at five-year intervals dating from the initial inspection.

Paragraph (b) specifies when a project development must be initially inspected. The timing of the initial inspection depends on the type of project. The first category of projects includes any development that has a dam that is more than 32.8 feet (10 meters) in height above streambed, or that impounds a reservoir with a gross storage capacity of more than 2,000 acre feet. The facility must be inspected not later than two years after the date of issuance of an order licensing the development, if it was constructed before the date of issuance of the order.

For any development that was constructed after the date of issuance of the order licensing or amending a license to include the development, the initial inspection under this subpart must be completed and the report on it filed not later than five years from the date of the first commercial operation or the date on which the reservoir first reaches its normal maximum surface elevation, whichever occurs first.

For any other development, the initial inspection must be completed and the report on it filed by a date specified by the Regional Engineer. The initial inspection must be made within two years following the date that the Regional Engineer notifies the licensee that an inspection and report is required.

Subparagraph (b)(4) provides that a Part 12 inspection made before the effective date of this regulation may be considered an initial inspection. However, the first report filed under this rule for a development must contain the information and analysis required by § 12.37(b).

§ *12.39 Taking corrective measures after the report.*

Section 12.39 explains the plan and schedule of corrective measures the applicant or licensee must file and implement under the supervision of the Regional Engineer. After reviewing several comments, the Commission believes that 30 days was not a sufficient time within which to prepare a plan and has increased the time to 60 days.

Subpart E—Other Responsibilities of Applicant or Licensee

This subpart explains several responsibilities that every applicant or licensee has regarding the operation and maintenance of a project development.

§ *12.40 Quality control program.*

Section 12.40 requires that a quality control program be maintained during any construction, repair, or modification of the project works or while taking any corrective measures. The Commission has modified the proposed rule to make clear in the final rule that the applicant or licensee must maintain a quality control program as may be required by the Regional Engineer. The Regional Engineer may decide not to require such a program for relatively minor work. Such a program must meet any requirements or standards set by the Regional Engineer and must be commensurate with the scope of the work being undertaken.

The proposed rule provided that quality control inspections must be conducted by the licensee, the design engineer, or an independent firm accountable to the licensee, and must not be performed by a construction contractor or firm accountable to the construction contractor. Some commenters, including licensees, supported this provision, while construction contractors opposed it. Construction contractors argue that they have interests in quality construction work that lead them to establish their own quality control programs and the proposed provisions would prohibit that. This point is well taken, and the rule has been modified to make clear that a construction contractor is not precluded from performing its own quality control inspections for its own purposes. Experience shows, however, that construction contractors may also have conflicting interests that may lead to neglect of the quality of work. Because of the potential for conflict of interest, it is important to provide for independent quality control inspections to ensure that the work has been performed at least up to the standards in the plans and specifications. Therefore, the final rule preserves such a requirement.

Under the final rule, if the licensee's or applicant's own personnel are performing the work, the licensee or applicant must provide for separation of authority between construction personnel and quality control personnel.

§ *12.41 Monitoring instruments.*

Section 12.41 requires that an applicant or licensee make provisions for instruments to monitor the performance of the project works whenever conditions are found during design, construction, or operation of the project that might affect the safety of the project or the project works.

§ *12.42 Warning and safety devices.*

Under § 12.42, warning and safety devices must be installed that, in the judgment of the Regional Engineer, are reasonably necessary to protect the public. This section requires an applicant or licensee to install, operate, and maintain safety and warning devices that "may reasonably be necessary or desirable." Many commenters objected that this standard was too broad. The final rule is unchanged. The Commission's primary concern is with the safety of the project and project works and the protection of public health and safety. The Commission and its authorized representatives do not intend to impose unreasonable burdens upon an applicant or licensee. But when matters of safety are at issue, it is better to err on the side of caution and not be stymied simply because of the difficulty of proving that a particular precaution is "necessary". If there is reasonable doubt about the need for a safety precaution, but not about its desirability, it should be taken.

§ *12.43 Power and communication lines and gas pipelines.*

Under § 12.43, the Commission requires a licensee to keep power and communication lines and gas pipelines from obstructing navigation or otherwise endangering the public. The Commission has added a paragraph (c) that authorizes the Regional Engineer to require a licensee or applicant to provide warning signs, giving the clearances for power or communication lines.

§ *12.44 Testing spillway gates.*

Section 12.44 requires at least annual operation of spillway gates and load-testing of the standby emergency power for spillway gate operation at regular intervals.

§ *12.45 Inspections by the public.*

Section 12.45 of the proposed rule required an applicant or a licensee to post a Public Notice at all major points of public access in the vicinity of the project dams or dikes, in order to obtain the assistance of the public in the protection of life, health, and safety.

Several commenters suggested omitting that proposed section. The commenters recommended that the Commission require the posting of a public notice on a limited basis to assess the effectiveness of such a program. Rather than impose a uniform requirement at this time, the Commission has omitted § 12.45 and will undertake an informal program of testing public notices at various representative projects, as suggested.

III. EFFECTIVE DATE

These rules are effective on March 1, 1981.

(Federal Power Act, as amended, 16 U.S.C. 792–828c: Department of Energy Organization Act, 42 U.S.C. 7101–7352; Executive Order No. 12009, 3 CFR 142 (1978))

In consideration of the foregoing, the Commission revises Part 12, Subchapter B, of Chapter 1, Title 18, Code of Federal Regulations, as set forth below, effective March 1, 1981.

By the Commission.
Lois D. Cashell,
Acting Secretary.

[¶ 30,226]

46 F. R. 9043 (January 28, 1981); 46 F. R. 21155 (April 9, 1981).

18 CFR Parts 351, 352, 356, 357, 360, 361, and 362

[Docket No. RM81-8; Order No. 119]

Regulation of Interstate Oil Pipelines

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: By this rule the Federal Energy Regulatory Commission transfers to Title 18 those regulations in Title 49, Parts 1200 to 1299, applicable to the Commission's oil pipeline jurisdiction. These rules, representing a portion of the oil pipeline rules, were delegated to the Federal Energy Regulatory Commission at the time of the Department of Energy Organization Act and have been utilized by the Commission to carry out its legislative mandate.

EFFECTIVE DATE: December 19, 1980.

FOR FURTHER INFORMATION CONTACT:

William Topping, Office of the General Counsel, 825 North Capitol Street, NE, Washington, D.C. 20426 (202) 357-8583

or

Peter Lefkin, Office of the General Counsel, 825 North Capitol Street, NE, Washington, D.C. 20426 (202) 357-8607.

SUPPLEMENTARY INFORMATION:

Order Redesignating and Duplicating Certain Oil Pipeline Regulations

Issued: December 19, 1980.

A. Background.

Jurisdiction over oil pipelines, as it relates to the establishment of rates or charges for the transportation of oil by pipeline or to the establishment of valuations for pipelines was transferred from the Interstate Commerce Commission (ICC) to the Federal Energy Regulatory Commission (FERC), pursuant to sections 306 and 402 of the Department of Energy Organization Act (DOE Act), 42 U.S.C. 7155 and 7172, and Executive Order No. 12009, 42 FR 46267 (September 13, 1977). Section 705(a) of the DOE Act provides that rules and regulations relating to functions transferred to the FERC shall continue in effect until modified by the FERC. The regulations relating to FERC's jursidiction over oil pipelines are presently contained in Title 49 of the Code of Federal Regulations (CFR). The FERC has ordered that rules and regulations in Title 49, which relate to the FERC's jurisdiction over oil pipelines, should remain in effect until modified by the FERC.[1] The FERC has also recognized that the oil pipeline regulations appearing in Title 49 of the Code of Federal Regulations should eventually be transferred from Title 49 to Title 18 of the Code of Federal Regulations.[2]

B. Transfer to Title 18.

This rulemaking will transfer to Title 18 those regulations in Title 49, Parts 1200 to 1299, applicable to FERC's oil pipeline jurisdiction.[3] Parts 1204, 1220, 1260, 1261, 1262, and a portion of Parts

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[1] Order No. 1, *Interim Regulations for the Operations of the Federal Energy Regulatory Commission*, "Order Providing for the Continuation of Functions Vested in, or Delegated to, the Federal Energy Regulatory Commission," 42 FR 55, 450 (1977).

[2] Order No. 62, *Uniform System of Accounts for Pipeline Companies and Attendant Reporting Forms*, "Order Amending Title of Account 670 of the Uniform System of Accounts for Pipeline Companies and Related Provisions and Forms," Docket No. RM80-4, p.2 (issued December 6, 1979).

[3] Transfer to Title 18 of regulations applicable to oil pipelines which are contained in Title 49, Parts 1000 to 1199 and Parts 1300 to End will be addressed at a future time.

1241 and 1200 [4] will be transferred to Title 18, or duplicated to contain the language that existed at the time the DOE Act took effect and any FERC modifications.[5]

The republished regulations contain technical modifications required because of the transfer of jurisdiction to the FERC or required because of the republication in Title 18 (*e.g.* cross references to redesignated sections). Additionally, because the ICC has modified §§ 1241.61 and 1241.62 since the transfer of oil pipeline jurisdiction to the FERC, this order recreates §§ 1241.61 and 1241.62 in total to read as those sections read at the time the DOE Act took effect.

As noted above, the Commission intends eventually to publish all regulations affecting its jurisdiction over oil pipelines in Title 18. This procedure, which the present rulemaking begins: (1) Will eliminate potential confusion between FERC's use and amendment of these regulations for pipelines subject to FERC's jurisdiction and the ICC's use and amendment of these regulations for pipelines subject to ICC's jurisdiction; (2) will aid administrative efficiency by combining all FERC regulations into one title, Title 18; and (3) will be consistent with the FERC's legislative mandate to continue rules and regulations relating to functions transferred to the FERC until modified by the FERC.

C. Effective Date.

Since this rule concerns a matter of agency practice and procedure and does not amend any substantive rules, notice and public procedure thereon is unnecessary pursuant to 5 U.S.C. 553(b). Therefore, the FERC finds good cause pursuant to 5 U.S.C. 553(d)(3) to make this rule effective immediately.

(Department of Energy Organization Act, (42 U.S.C. 7101 *et seq.*) E.O. 12009, 42 FR 46267, Interstate Commerce Act, *as amended.* (49 U.S.C. 1 *et seq.*))

In consideration of the foregoing, Part I, Chapter I of Title 18 of the Code of Federal Regulations is amended and Subchapters Q, R, and S are issued as final regulations as set forth below, effective December 19, 1980.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,227]

46 F. R. 9921 (January 30, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Texas-3); Order No. 125]

High-Cost Gas Produced from Tight Formations; Cisco Sandstone Formation

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR § 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission

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[4] Sections 1200.1, 1241.1 1241.61 and 1241.62.

[5] The Interstate Commerce Commission, contemporaneously with this rulemaking, is eliminating Part 1204, a portion of Part 1241, Parts 1200 and 1261 from Title 49 and, consistent with this rulemaking, the ICC is redesignating these Parts to the applicable Title 18 Parts. Because the ICC is continuing to use § 1200.1, Part 1220, 1241.1 and Part 1262 for regulating common carriers subject to it jurisdiction, these Parts are being duplicated in Title 18 for our purposes.

recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Railroad Commission of Texas that the Cisco Sandstone Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: January 23, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or John Bassett, (202) 357-8589/Ting Chin, (202) 357-8595.

SUPPLEMENTARY INFORMATION:

Issued: January 23, 1981.

The Commission hereby amends § 271.703(d) of its regulations to include the Cisco Sandstone Formation as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by the Director, OPPR, issued October 24, 1980, (45 FR 71587, October 29, 1980),[1] based on a recommendation by the Railroad Commission of Texas (Texas) in accordance with § 271.703(c), that the Cisco Sandstone Formation be designated as a tight formation.

Evidence submitted by Texas and the commenters supports Texas' assertion that the Cisco Sandstone Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Texas recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately established good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. § 3301-3432; Administrative Procedure Act, 5 U.S.C. 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective January 23, 1981.

By the Commission.

Lois D. Cashell,
Acting Secretary.

[¶ 30,228]

46 F. R. 9921 (January 30, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Colorado-1); Order No. 124]

High-Cost Gas Produced From Tight Formations; Wattenberg J Sand Formation

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR § 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts, with certain modifications, the recommendation of the Colorado Oil and Gas Conservation Commission that the Wattenberg J Sand Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: January 23, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8559.

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[1] Comments were invited and two were received. No party requested a hearing in the matter, and no hearing was held.

SUPPLEMENTARY INFORMATION:

Issued January 23, 1931.

The Commission hereby amends § 271.703(d) of its regulations to include the Wattenberg J Sand Formation as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by the Director, OPPR, on September 23, 1980, (45 FR 65608, October 3, 1980),[1] based on a recommendation by the Colorado Gas Conservation Commission (Colorado) that the Wattenberg J Sand Formation should be designated as a tight formation in accordance with § 271.703(c).

Evidence submitted by Colorado and the commenters supports Colorado's assertion that the Wattenberg J Sand Formation meets the guidelines contained in § 271.703(c)(2). The Commission generally adopts the Colorado recommendation, with the modification discussed below.

In the Preamble to the Interim Rule in Docket No. RM79-6, issued on February 20, 1980, which promulgated the tight formation designation procedures, the Commission expressed its policy of excluding from designated tight formations any areas which had been substantially developed by infill drilling. The Commission stated that:

> While new infill wells are not excluded from qualification under this rule, jurisdictional agencies should be sensitive to the fact that some portions of tight formations have been developed to such an extent as to indicate that the incentive maximum lawful price is not necessary to encourage full production of the formation. If the agency has information which indicates such portions can be developed without the incentive price, such portions should be excluded from the jurisdictional agency's recommendation. *(Memeo, p. 27.)*

On June 27, 1980 the Office of General Counsel issued a letter of interpretation[2] regarding the significance of this discussion to the Interim Rule. According to that interpretation, under the Interim Rule, if a jurisdictional agency had information which in its judgment indicated that a portion of a formation, which was being developed pursuant to an infill drilling program, could be developed without the tight formation incentive price, such portion should be excluded from the recommendation. In issuing the Final Rule the Commission clarified the uncertainty that had been created under the Interim Rule by adding a guideline specifically dealing with formations or portions of formations that are currently being developed by infill drilling programs. This guideline is contained in § 271.703(c)[illegible] of the final regulations and provides that:

> *(B) If the formation or any portion thereof was authorized to be developed by infill drilling prior to the date of recommendation and the jurisdictional agency has information which in its judgment indicates that such formation or portion subject to infill drilling can be developed without the incentive price established in paragraph (a) of this section then the jurisdictional agency shall not include such formation or portion thereof in its recommendation.*

In its review of the recommendation, the Commission found that Colorado submitted information in this docket and in a separate docket, indicating that certain areas within the recommended formation had been authorized to be developed by infill drilling prior to the date the recommendation was made, and that certain areas within the infill area can be developed without the incentive price.[3] Accordingly, pursuant to the Interim and the Final Rules, the Commission has excluded these areas from the area to be designated as a tight formation in the Commission's regulations. The excluded areas include only those developed 320-acre drilling units for which the infill drilling order authorized the drilling of additional wells. The excluded areas do not include those drilling units covered by the infill order, in which wells were not completed for production in the Wattenberg J Sand at the time the infill order was issued. Colorado's recommendation, as modified, (see Appendix), satisfies the guidelines for designation as a tight formation in § 271.703(c) of the Commission's regulations. The Commission amends § 271.703(d) to include the Wattenberg J Sand Formation as a designated tight formation. This limited exclusion is consistent with statements of Colorado and Amoco Production Co. in the record, to the effect that the available economic data may not be directly applicable to the entire Wattenberg J Sand area covered in the infill drilling order. The exclusion further comports with the language in the Preamble to Order No. 99, that infill drilling does not include drilling activity where the original units had not been defined prior to the adoption of the rules which permitted drilling additional wells on the original units. The exclusion does not preclude future consideration of these areas as tight formations, if information and economic data become available which show that all or part of the excluded area would not be developed absent the incentive price under section 107(c)(5).

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[1] Comments were invited and received. No party requested a hearing in this matter, and no hearing was held.

[2] Letter from Robert R. Nordhaus, General Counsel, to John Soule (June 27, 1980), sent to all jurisdictional agencies on same date by letter from Howard [illegible], Director, Division of NGPA Compliance.

[3] Colorado issued an Infill Drilling Order covering portions of the Wattenberg J Sand Formation, in Colorado Oil and Gas Conservation Commission's Order No. [illegible]. In the hearing and testimony

This amendment shall become effective immediately. The Commission has found that the public interest dictates new natural gas supplies be developed on an expedited basis, and therefore that incentive prices should be made available as soon as possible. The need to make incentive prices available immediately creates good cause to waive the thirty day publication period.

(Department of Energy Organization Act, 42 U.S.C. § 7101 et seq.; Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301–3432; Administrative Procedure Act, 5 U.S.C. § 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective January 23, 1981.

By the Commission.

Lois D. Cashell,

Acting Secretary.

[¶ 30,229]

46 F. R. 9925 (January 30, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Texas-4); Order No. 126]

High-Cost Gas Produced From Tight Formations; Vicksburg UV Formation

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR § 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Railroad Commission of Texas that the Vicksburg UV Formation be designated as a tight formation under § 271.703(d).

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related to Order No. 232–20, information presented show that portions of the Wattenberg J Sand were economical to develop without the incentive price allowed under section 107(c)(5). This information was submitted to the Commission in Docket No. RA79-3, as part of Colorado's application for approval of alternative filing requirements under § 274.207 of the Commission's regulations.

EFFECTIVE DATE: January 23, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or John Bassett, (202) 357-8589/Ting Chin, (202) 357-8595.

SUPPLEMENTARY INFORMATION:

Issued: January 23, 1981.

The Commission hereby amends § 271.703(d) of its regulations to include the Vicksburg UV Formation as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by the Director, OPPR, issued October 24, 1980, (45 FR 71580, October 29, 1980),[1] based on a recommendation by the Railroad Commission of Texas (Texas) in accordance with § 271.703(c), that the Vicksburg UV Formation be designated as a tight formation.

Evidence submitted by Texas and the commenters supports Texas' assertion that the Vicksburg UV Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Texas recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately established good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. § 7101 et seq.; Natural Gas Policy Act of 1978, 15 U.S.C. § 3301–3432; Administrative Procedure Act, 5 U.S.C. 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective January 23, 1981.

Lois D. Cashell,
Acting Secretary.

[¶ 30,230]

46 F. R. 9923 (January 30, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Texas-5) (Order No. 127)]

High-Cost Gas Produced from Tight Formations; Vicksburg Y Formation

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR § 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Railroad Commission of Texas that the Vicksburg Y Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: January 23, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or John Bassett, (202) 357-8589/Ting Chin, (202) 357-8595.

SUPPLEMENTARY INFORMATION:

Issued: January 23, 1981.

The Commission hereby amends § 271.703(d) of its regulations to include the Vicksburg Y Formation as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by the Director, OPPR, issued October 24, 1980, (45 FR 71589, October 29, 1980),[1] based on a recommendation by the Railroad Commission of Texas (Texas) in accordance with § 271.703(c), that the Vicksburg Y Formation be designated as a tight formation.

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[1] Comments were invited and two were received. No party requested a hearing in this matter, and no hearing was held.

Evidence submitted by Texas and the commenters supports Texas' assertion that the Vicksburg Y Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Texas recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period. *(Department of Energy Organization Act, 42 U.S.C. § 7101 et seq.; Natural Gas Policy Act of 1978, 15 U.S.C. § 3301-3432; Administrative Procedure Act, 5 U.S.C. 553)*

For the reasons stated herein, Part 271 of Subchapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective January 22, 1981.

By the Commission.

Lois D. Cashell,

Acting Secretary.

[¶ 30,231]

46 F. R. 10141 (February 2, 1981)

18 CFR Part 271

[Docket No. RM80-53]

Publication of Prescribed Maximum Lawful Prices Under the Natural Gas Policy Act of 1978

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: Pursuant to the authority delegated by 18 CFR § 357.307(1), the Director of the Office of Pipeline and Producer Regulation revises and publishes the maximum lawful prices prescribed under Title I of the Natural Gas Policy Act (NGPA) for the months of February, March and April, 1981. Section 101(b)(6) of the NGPA required that the Commission compute and publish the maximum lawful prices before the beginning of each month for which the figures apply.

EFFECTIVE DATE: January 27, 1981.

FOR FURTHER INFORMATION CONTACT: Kenneth A. Williams, Director, OPPR, (202) 357-8500.

January 26, 1981.

Section 101(b)(6) of the Natural Gas Policy Act of 1978 (NGPA) requires that the Commission compute and make available maximum lawful prices and inflation adjustments prescribed in Title I of the NGPA before the beginning of any month for which such figures apply.

Pursuant to this requirement and § 375.307(1) of the Commission's regulations, which delegates the publication of such prices and inflation adjustments to the Director of the Office of Pipeline and Producer Regulation, the maximum lawful prices for the months of February, March and April, 1981, are issued by the publication of the price tables for the applicable quarter. Pricing tables are found in § 271.101(a) of the Commission's regulations. Table I of § 271.101(a) specifies the maximum lawful prices for gas subject to sections 102, 103, 106(b)(1)(B), 107(c)(5), 108, and 109 of the NGPA. Table II of § 271.101(a) specifies the maximum lawful prices for sections 104 and 106(a) of the NGPA. Table II of § 271.101(a) contains the inflation adjustment factors.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

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[1] Comments were invited and two were received. No party requested a hearing in this matter, and no hearing was held.

[¶ 30,232]

46 F. R. 10460 (February 3, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Louisiana-1); Order No. 129]

High-Cost Gas Produced From Tight Formations; Final Rule

Issued January 27, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR § 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Louisiana Office of Conservation that the Arkadelphia Formation designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: January 27, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Ting Chin, (202) 357-8595/John Basset, (202) 357-8589.

The Commission hereby amends § 271.703(d) of its regulations to include the Arkadelphia Formation as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued October 28, 1980 (45 FR 72687, November 3, 1980)[1] based on a recommendation by the Louisiana Office of Conservation (Louisiana) with § 271.703(c), that the Arkadelphia Formation be designated as a tight formation.

Evidence submitted by Louisiana and one commenter supports Louisiana's assertion that the Arkadelphia Formation meet the guidelines contained in § 271.703(c)(2). The Commission concurs with the Louisiana recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. § 3301-3432; Administrative Procedure Act, 5 U.S.C. 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective January 27, 1981.

Lois D. Cashell,
Acting Secretary.

[¶ 30,233]

46 F. R. 10460 (February 3, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Wyoming-3; Order No. 128]

High-Cost Gas Produced From Tight Formations; Final Rule

Issued January 27, 1981.

AGENCY: Federal Energy Regulatory Commission.

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[1] Comments were requested and received. No party requested a public hearing in this proceeding and no hearing was held.

ACTION: Final rule.

SUMMARY: The Federal Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR § 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Wyoming Oil and Gas Conservation Commission that the Fort Union Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: January 27, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8559.

The Commission hereby amends § 271.703(d) of its regulations to include the Fort Union Formation in the Pinedale Field Sublette County, Wyoming as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued November 28, 1980 (45 FR 76700, October 20, 1980)[1] based on a recommendation by the Wyoming Oil and Gas Conservation Commission (Wyoming) in accordance with § 271.703(c), that the Fort Union Formation be designated as a tight formation.

Evidence submitted by Wyoming and one commenter supports Wyoming's assertion that this formation meet the guidelines contained in § 271.703(c)(2). The Commission adopts the Wyoming recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432; Administrative Procedure Act, 5 U.S.C. 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective January 27, 1981.

Lois D. Cashell,
Acting Secretary.

[¶ 30,234]

46 F. R. 11251 (February 6, 1981)

18 CFR Part 292

[Docket No. RM79-54; Order No. 70-D]

Order Amending Regulations

Issued: January 28, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Order Amending Regulations.

SUMMARY: The Federal Energy Regulatory Commission (Commission) hereby adopts an order amending regulations. The Order amends § 292.206 of the Commission's rules which establishes the ownership criteria for qualifying facilities. The Order enables certain "electric utilities" which are not "primarily engaged in the generation or sale of electric energy" to own up to 100 percent of a qualifying facility.

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[1] Comments were requested and received. No party requested a public hearing in this proceeding and no hearing was held.

EFFECTIVE DATE: January 28, 1981.

FOR FURTHER INFORMATION CONTACT:

Glenn Berger, Office of the General
Counsel, Federal Energy Regulatory
Commission, 825 North Capitol
Street, NE., Washington, D.C. 20426
(202) 357–8033
or
Michael Kessler, Office of the General
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Commission, 825 North Capitol
Street, NE., Washington, D.C. 20426
(202) 357–8033

The Federal Energy Regulatory Commission (Commission) has the authority to certify small power production and cogeneration facilities as qualifying facilities, pursuant to § 292.207 of the Commission's rules. Qualifying status exempts qualifying facilities from regulation under certain provisions of the Federal Power Act (FPA),[1] from regulation under the Public Utility Holding Company Act of 1935 (PUHCA)[2] and from certain state law and regulation [3] and allows such facilities to obtain the "avoided cost" rate for power purchased by an electric utility.

Recent applications to the Commission by persons seeking qualifying status have raised the issue of whether the 50 percent ownership restriction for electric utilities other than those generating power solely from cogeneration or small power production, established in § 292.206(b) of the Commission's rules, is consistent with the general rules of ownership established in section 201 of the Public Utility Regulatory Policies Act (PURPA) and § 292.206(a) of the Commission's rules.

Section 3(22) of the FPA, as amended by section 201 of PURPA, broadly defines an "electric utility" as "any person or State which sells electric energy". Section 3(17)(C)(ii) of the FPA, as amended by section 201 of PURPA, requires that a qualifying facility be "owned by a person not primarily engaged in the generation or sale of electric power (other than electric power *solely* from cogeneration facilities or small power production facilities)" (emphasis added). This requirement is implemented in § 292.206(a) of the Commission's rules. Section 292.206(b) of the Commission's rules, provides, *inter alia*, that a facility of which an electric utility or utilities, or an electric utility holding company or companies, or any combination thereof, owns more than 50 percent of the equity interest cannot obtain qualifying status.

Thus, a cogeneration or small power production facility of which an electric utility or utilities, or an electric utility holding company or companies, or any combination thereof, owns more than 50 percent of the equity interest, can be a qualifying facility only if all of the power gererated and sold by the parent utility or holding company is generated from cogeneration or small power production facilities.

Section 292.206(b) of the Commission's rules also provides that:

> If a wholly or partially owned subsidiary of an electric utility or electric utility holding company has an ownership interest of a facility, the subsidiary's ownership interest shall be considered as ownership by an electric utility or electric utility holding company.

In determining whether a facility is owned by an electric utility or an electric utility holding company, the Commission looks "upstream" to the parent company of a subsidiary which owns a cogeneration or small power production facility.

The Commission has recognized that the ownership restrictions for qualifying facilities in the original rule were overly strict in certain respects. In particular, In Order Nos. 70–B [4] and 70–C,[5] the

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[1] 18 C.F.R. § 292.601.

[2] *Id.* § 292.602(b).

[3] *Id.* § 292.602(c).

[4] 45 FR 52779 (Aug. 8, 1980).

[5] 45 FR 66787 (Oct. 8, 1980).

In that order, the Commission amended its regulations to exclude from the definition of "electric utility holding company" any such company which is exempt by rule or order of the SEC pursuant to sections 3(a)(3) or 3(a)(5) of the Public Utility Holding Company Act of 1935.

Commission recognized that "certain companies which are not 'primarily engaged in the generation or sale of electric power' may nevertheless be classified as 'electric utilities' or 'electric utility holding companies'."

The Commission is aware of two cases in which a company would presently be defined as an "electric utility" under the FPA but should not be considered to be "primarily engaged in the generation or sale of electric power" for purposes of ownership of a qualifying facility.

The Commission will permit otherwise eligible cogeneration and small power production facilities owned by these types of companies to be qualifying facilities. However, the FPA requires that the Commission regulate any wholesale sales of power in interstate commerce where the power is generated from sources other than cogeneration or small power production facilities.[6] Only if a company can show that all of its wholesale power sales are from cogeneration or small power production facilities will such sales be exempt from regulation under the FPA.

CASE 1A—Exempt Electric Utility Holding Company

The first type of case involves a parent and subsidiary company ownership situation. In this case, the company which owns a small power production facility or cogeneration facility is also a subsidiary of an exempt electric utility holding company.

In Order No. 70–C[7] the Commission determined that electric utility holding companies that are exempt as such pursuant to either section 3(a)(3) or 3(a)(5) of the Public Utility Holding Company Act (PUHCA) will not be subject to the 50 percent ownership restriction.[8] Thus, a cogeneration or small power production facility which is directly owned by an exempt electric utility holding company can be a qualifying facility.

The Commission believes that it would be inconsistent not to allow a subsidiary electric utility to do directly what its exempt parent company can do indirectly. Thus, a subsidiary of a PUHCA section 3(a)(3) or 3(a)(5) exempt electric utility holding company will be allowed to own 100 percent of a qualifying facility whether or not the subsidiary is "primarily engaged in the generation or sale of electric power."

CASE 1B—Registered Electric Utility Holding Company

Under the rule stated above, if the parent company is an exempt electric utility holding company, any subsidiary of such a company may own 100 percent of a facility without disqualification. In the case of a parent company which is a registered electric utility holding company, § 292.206(b) of the Commission's rules prohibits a facility, of which the parent owns more than 50 percent, from obtaining qualifying status. For the purpose of determining the ownership of a facility, § 292.206(b) of the Commission's rules requires that the Commission look upstream to a parent electric utility or electric utility holding company. Thus, a facility, of which a subsidiary of a registered electric utility holding company owns more than 50 percent, cannot obtain qualifying status.

CASE 2—Exempt Electric Utility

The second case is, similarly, a two-level ownership situation. In this case,

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The Commission reasoned that:

a determination by the SEC that an electric utility holding company is exempt as such under either section 3(a)(3) or 3(a)(5) of PUHCA satisfies the requirement that a qualifying facility may not be owned by a person primarily engaged in the generation or sale of electric power.

[6] The State authorities may still regulate any retail sales made by a company, regardless of the company's ability to own qualifying facilities, and regardless of whether the sales are made from qualifying facilities.

[7] 45 FR 66787 (Oct. 8, 1980).

[8] Under § 292.202(n) of the Commission's rules, such companies are not considered to be "electric utility holding companies."

however, the subsidiary is an "electric utility" pursuant to section 3(22) of the FPA but has been declared by the SEC *not* to be an "electric utility" pursuant to section 2(a)(3)(A) of PUHCA.

Section 2(a)(3) of PUHCA defines an electric utility company as "any company which owns or operates facilities used for the generation, transmission, or distribution of electric energy for sale."[9] This section of PUHCA also provides that the SEC:

> shall by order declare a company operating any such facilities not to be an electric utility company if the Commission finds that (A) such company is primarily engaged in one or more businesses other than the business of an electric utility company, and by reason of the small amount of electric energy sold by such company it is not necessary in the public interest or for the protection of investors or consumers that such company be considered an electric utility company.[10]

The SEC may order such exclusion either by rule (where the company falls below certain *de minimus* standards) or on a case-by-case basis.

In this case, the Commission believes that a facility owned 100 percent by such a subsidiary should be allowed to obtain qualifying status. The statutory standard for exclusion of the subsidiary company from the definition of "electric utility" under PUHCA is identical to the ownership requirements expressed in sections 17(C)(ii) and 18(B)(ii) of the FPA. Both statutes require that the company *not* be primarily engaged in the generation or sale of electric power.

Thus, exclusion under section 2(a)(3)(A) of PUHCA means that a subsidiary company within a holding company system is not an "electric utility" for purposes of the ownership restriction established in § 292.206(b) of the Commission's rules. Therefore, a facility owned 100 percent by such a subsidiary company may obtain qualifying status.

The Commission notes that on May 19, 1980, Elizabethtown Gas Company filed a Petition for Review of Order No. 70 and of the Commission's Order on Rehearing of Order Nos. 69 and 70 in the United States Court of Appeals for the District of Columbia Circuit. On June 30, 1980, the Commission filed with the court the Certificate of Record in Lieu of Record. Under section 313(b) of the Federal Power Act, the Court has exclusive jurisdiction to modify those orders. Accordingly, this order is issued subject to the courts permission.

The Commission notes that several applications for certification as a qualifying small power production facility or cogeneration facility are pending before the Commission. As a result of the amendments to the rules in this Order, the pending applications may obtain qualifying status. The Commission believes it is in the public interest to issue the certification of qualifying status as soon as possible so the applicants may begin to produce power which will help the nation reduce its dependence on imported oil. For this reason, the Commission finds good cause to waive the 30 day requirement set forth in 5 U.S.C. § 553(d) and to make this rule effective on January 28, 1981.

The Commission Orders

Section 292.206 is amended as set forth below effective January 28, 1981, for the reasons set forth below.

(Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 2601 *et. seq.*; Energy Supply and Environmental Coordination Act, 15 U.S.C. § 791 *et. seq.*; Federal Power Act, as amended, 16 U.S.C. § 792 *et. seq.*; Department of Energy Organization Act, 42 U.S.C. § 7101 *et. seq.*; E.O. 12009, 3 CFR 142 (1978)).

In consideration of the foregoing, the Commission amends Part 292 of Chapter I, Title 18, Code of Federal Regulations, as set forth below, effective January 28, 1981.

By the Commission.

Kenneth F. Plumb,

Secretary.

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[9] 15 U.S.C. § 79b(3).

[10] *Id.*

[¶ 30,235]

46 F. R. 11811 (February 11, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Texas—6)]

High-Cost Gas Produced From Tight Formations; Final Rule

Issued: February 5, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR § 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Texas Railroad Commission that the Midway (11,740′) Sandstone Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: February 5, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or John Bassett, (202) 357-8657/Ting Chin (202) 357-8769.

SUPPLEMENTARY INFORMATION: The Commission hereby amends § 271.703(d) of its regulations to include the Midway (11,740′) Sandstone Formation as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued December 3, 1980 (45 FR 81063, December 8, 1980)[1] based on a recommendation by the Railroad Commission of Texas (Texas) in accordance with § 271.703(c), that the Midway (11,740′) Sandstone Formation be designated as a tight formation.

Evidence submitted by Texas and the commenters supports Texas' assertion that the Midway (11,740′) Sandstone Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Texas recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*: Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3432; Administrative Procedure Act, 5 U.S.C. 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective February 5, 1981.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,236]

46 F. R. 12198 (February 13, 1981)

18 CFR Parts 154, 270 and 273

[Docket No. RM80-54; Order No. 131]

Amendments to Part 273 Regulations Under the Natural Gas Policy Act

Issued: February 9, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

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[1] Comments were invited and two were received. No party requested a public hearing in this matter and no hearing was held.

ACTION: Final rule.

SUMMARY: Section 503(e)(2)(A) of the Natural Gas Policy Act of 1978 (NGPA), (15 U.S.C. 3414) directs the Federal Energy Regulatory Commission (Commission) to adopt rules or orders to permit collection of the maximum lawful price applicable to the first sale of natural gas for which an application for a determination has been filed and is pending. Section 503(e)(2)(B) also requires that any such collections be subject to refund and directs the Commission to prescribe regulations providing assurance that funds are available for any refunds if a determination results in qualification for a lower maximum lawful price than the one collected through the interim collection process.

The Commission is amending its regulations which implement section 503(e)(2)(A) under Parts 154, 270 and 273 of its regulations. Interim and retroactive collection filings with the Commission have been eliminated except where natural gas is subject to jurisdiction under the Natural Gas Act and a rate schedule on file with the Commission. All sellers will be required to notify their purchasers of their intent to make interim collections. An interim collection will constitute a general undertaking to comply with the refund provisions of Part 273. A successive interim collection will be allowed for a new application for determination where a well previously has received an affirmative eligibility determination. The information to be required in refund reports has been revised.

EFFECTIVE DATE: The amendments to §§ 273.202, 273.203 and 273.204 are effective February 9, 1981. All other amendments shall be effective March 16, 1981.

FOR FURTHER INFORMATION CONTACT: Dan White, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Room 6112D, Washington, D.C. 20426 (202) 357-8577.

SUPPLEMENTARY INFORMATION:

I. Background

Section 503(e)(2)(A) of the Natural Gas Policy Act of 1978 (NGPA), (15 U.S.C. 3414) directs the Federal Energy Regulatory Commission (Commission) to adopt rules or orders to permit collection of the maximum lawful price for which an application for a determination has been filed and is pending. Section 503(e)(2)(B) also requires that any such collections be subject to refund and directs the Commission to prescribe regulations providing assurance that funds are available for any refunds if a determination results in qualification for a lower maximum lawful price than the one collected through the interim collection process.

The Commission has implemented section 503(e) in Part 273 of its regulations. Part 273 was issued as an interim rule on December 1, 1978, 43 FR 56448 (1978). It was reissued with modifications as a final regulation on June 19, 1979, in Order No. 36, Docket No. RM79-53, 44 FR 37491 (1979).

The previously existing regulations at §§ 273.202 and 273.203 prescribed requirements for interim collections of the maximum lawful price for which a sale is claimed to be eligible while the related final eligibility determination is pending. Sellers were required to submit certain information to the Commission prior to making interim collections. If the maximum lawful price for a particular first sale was finally determined to exceed the price collected for any period between the date of filing for the determination and the date on which the eligibility determination became final, § 273.204 provided that the seller could retroactively collect the difference to the extent contractually authorized. Any seller who made a retroactive collection was obligated to make a retroactive collection filing with the Commission. If the final eligibility determination disqualified the sale of the gas for as high a rate as was collected pursuant to Part 273, § 273.302 required refund of the difference and the filing of a refund report.

The Commission designed the filing requirements in Part 273 partly to ensure that the requirements of section 4(d) of the Natural Gas Act (15 U.S.C. 717c) were met. That section requires that a producer provide notice to the Commission and the public of any proposed change in existing rates for sales of natural gas subject to the Natural Gas Act. In Order No. 15, Docket No. RM79-4, issued November 17, 1978 (43 FR 55756 (1978)), the Commission concluded that the filing and notice requirements of the Natural Gas Act are deemed satisfied if a producer has fulfilled the interim and retroactive collection filing requirements of Part 273. That policy is expressed in § 154.94(i) of the regulations.

On May 7, 1980, the Commission issued a Notice of Proposed Rulemaking in the present docket to amend the interim and retroactive collection and refund reporting requirements. Written comments were to be submitted by June 16, 1980. The proposal would have amended the regulations to provide that (1) a filing with the Commission is required for making interim or retroactive collections only if the sale is subject to a producer rate schedule and (2) such a filing is required only if a notice of intent to make interim or retroactive collection of the price authorized by the NGPA category has not been previously filed under the applicable rate schedule. The proposal would have also modified the referred reporting requirements. Sixteen written comments were received. In addition, a public hearing was held on July 16, 1980, at the Commission in Washington, D.C.

These amendments are issued largely as proposed. They amend the previously existing regulations to eliminate interim and retroactive collection filings with the Commission unless the gas is subject to the Commission's jurisdiction and subject to a rate schedule on file with the Commission.[1] Additional amendments have been included which, among other things, modify the restriction against making interim collections if collections have been made under a previous application.

II. Discussion of the Comments

(A) *Sections 273.202(d), 273.203(c) and 273.204(c)(3).*

(1) *Filing and Notice Requirements.* Prior to the issuance of these amendments, the regulations required that an interim collection filing be submitted on a well-by-well basis (see §§ 273.202(d) and 273.203(c)). Similarly, § 273.204(c)(3) required a retroactive collection report. In the Notice of Proposed Rulemaking, the Commission proposed to eliminate interim and retroactive collection filings except where required under section 4(d) of the Natural Gas Act. Where required under section 4(d) the Commission proposed to require only one interim collection filing for each NGPA category under a particular rate schedule regardless of the number of wells in each category. For retroactive collections, the Commission proposed to require one filing for each NGPA category under a given rate schedule if the provisions of the Natural Gas Act continue to apply after the determination by the jurisdictional agency has become final. The Commission also stated it would consider comments on whether producers should be permitted to make a blanket filing indicating an intent to make all NGPA interim and retroactive collections under a rate schedule filed under the Natural Gas Act, or whether, under the Natural Gas Act, producers with rate schedules on file with the Commission may be relieved of the obligation to make any interim and retroactive collection filings.

As amended by this rule the regulations now require sellers to serve each purchaser with notice of all interim collections for the sale of gas. This is required with respect to gas not subject to a rate schedule on file with the Commission under the Natural Gas Act as well as gas covered by such a rate schedule. With respect to gas which is subject to a rate schedule on file with the Commission, the seller must also submit a filing with the Commission. This filing is required even if section 601 of the NGPA removes from Natural Gas Act jurisdiction gas which qualifies under the category for which the application was filed. Such removal does not occur until the final determination is obtained. For retroactive collection, a seller is required to serve any purchaser with a notice of retroactive collection and make a filing with the Commission for gas which remains subject to the provisions of the Natural Gas Act after a determination has become final.

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[1] Gas subject to the Commission's jurisdiction remains subject until the final determination is obtained even if the category for which the application is filed is section 107(c)(1) through (4), 102(c), or 103(c).

Only one comment argued that the Commission should relieve all producers of submitting interim or retroactive collection filings. This position was advocated because section 4(d) of the Act states, *"Unless the Commission otherwise orders,* no change shall be made by a natural gas company in any such rate, change, classification, or service, or in any rule, regulations or contract relating thereto, except after thirty days' notice to the Commission and to the public." [Emphasis added.] While the Commission may have the authority to eliminate the notice, such a decision would adversely affect protest procedures, discussed below. Therefore, for policy reasons we have chosen not to eliminate the notice to the Commission and the public. Moreover such a decision would undermine the regulations in § 154.94(i) since decisions made in Order No. 15, which amended the regulation at § 154.94(i), were based upon the continued requirement of interim and retroactive collection filings.

Most comments advocated a blanket filing whereby a seller indicates its intent to make all authorized interim and retroactive collections, rather than a filing for each NGPA price category in each rate schedule. These comments asserted that the filing burden on producers would be reduced, the information filed would be more manageable, and the statutory requirement of notice would still be met.

One pipeline commenter opposed a blanket filing procedure because of the ramifications blanket filings would have on the protest procedure. (See § 154.941 (i) and (j)). The comment maintained that interstate pipeline purchasers must receive notice of a producer's assertion of the right to collect a maximum lawful price under the NGPA in a form which would be adequate to identify the well and category for which an interim or retroactive collection is being made. Without such an ability to identify this specific information, the pipeline asserted that it would not be able to ascertain whether an evidentiary submission and a protest should be made. Without adequate information duplicative and unnecessary protests and evidentiary submissions might be filed.

The Commission agrees that purchasers should have available enough specific information to permit them to ascertain whether an evidentiary submission or a protest should be made. The blanket filing suggested by other commenters will not provide that information. As a result, the Commission believes that a pipeline should receive notice of an interim or retroactive collection for each NGPA category for each rate schedule as proposed in the Notice of Proposed Rulemaking.

The Commission is concerned that interim and retroactive collection filing requirements impose only the minimum regulatory burden on producers necessary to satisfy the requirements of section 4(d) of the Natural Gas Act. Therefore, a particular interim or retroactive collection filing which is filed for gas in an NGPA category in a particular rate schedule will satisfy the filing requirements for all future interim and retroactive collections covering gas in that category and rate schedule. No additional filing with the Commission is required to satisfy section 4(d) of the Natural Gas Act for subsequent interim or retroactive collections. These requirements should impose even less filings than would occur if we implemented a blanket filing procedure. As the regulations are being implemented, we predict very few additional filings will be required since interim and retroactive collection filings have already been made for most gas subject to a rate schedule.

Comments were received questioning the applicability of the filing requirements under Part 273 to intrastate sales and sales under small producer certificates. Under the amendments contained in this order, only when a producer is selling gas subject to the jurisdiction of the Natural Gas Act, and has a rate schedule on file with the Commission, are interim or retroactive collection filings required. Small producers are not required to file rate schedules under the Natural Gas Act and intrastate sales were never covered by the Natural Gas Act. Therefore, the interim and retroactive collection filing provisions in Part 273 do not extend to sales of intrastate gas and sales under small producer certificates. The Commission stresses, however, that the record keeping and filing requirements for possible refunds under § 273.302, the escrow provisions of the amended § 273.202(d)(2), and the notice provisions of §§ 273.202, 273.203 and 273.204 apply to all first sales.

(2) *Retention of the Requirement to File a Form No. 121 as Part of an Interim Collection Filing and Notice to Each Purchaser.* The present interim collection regulations require Form No. 121 to be filed with the Commission and served on each purchaser. Commenters pointed out that this form is already served on purchasers under § 274.201(d) when an application for determination is filed with a jurisdictional agency. The commenters claimed that requiring a copy of this form to be served on purchasers a second time is unnecessary and duplicative.

One pipeline commenter asserted that Form No. 121 should continue to be required as part of the notice to the purchaser because the form is a significant time-saving aid in identifying the wells and rate schedules subject to an interim collection. The Commission has decided to retain Form No. 121 as part of both an interim collection filing and of the notice to the purchaser. The Commission believes that to continue to require a photocopy of this very short form in interim collection filings and notices does not impose an unreasonable burden on producers and provides purchasers with needed information. The Commission will permit a seller to serve notice to a purchaser concurrently under Parts 273 and 274. This type of notice would require the inclusion of only one Form No. 121.

(B) *New Exceptions to the Rule in Section 273.202(e) Which Limit Interim Collection to Only One Per Well.*

Section 273.202(e) presently permits interim collections to be made only one time per well. For instance, if an application for a section 103 determination is filed and interim collections are made, no interim collections could be made if a subsequent application to qualify the gas under section 108 is filed. Many comments received urged modification of the restriction, arguing that this limitation is unfair and unduly restrictive where a well previously had received an affirmative jurisdictional agency determination under a different NGPA price category, or the new application seeks another section 108 stripper well determination after the well had lost that status because of a temporary increase in production.

The prohibition against more than one interim collection for the same well was promulgated by the Commission to prevent successive interim collections for an NGPA price category where the first jurisdictional agency determination was negative. The concern was that successive filings might enable a producer to charge higher prices in multiple interim collections where no good faith reasonable grounds existed to conclude that the gas qualifies under the price category for which application is made. The Commission also believed that the retroactive collection provisions adequately protected the seller.

The Commission no longer feels these considerations have merit where an affirmative jurisdictional agency determination under an NGPA category has previously been made. The Commission's experience since enactment of the NGPA indicates the interim collection process has not been abused. A purchaser can obtain adequate protection by requiring escrow of amounts received in an interim collection in excess of the otherwise applicable maximum lawful price. The present limitation in § 273.202(e) is revised to permit more than one interim collection where a well has previously received an affirmative eligibility determination. This amendment will, probably, most affect section 108 stripper wells that have lost that status because of a temporary increase in production. When the production falls back to qualifying levels the producer will be able to make interim collections when a new application is filed.

(C) *Designation by a Seller or Reseller for Notification Requirements for Interim Collection.*

A seller's designee under § 273.103 presently can make filings with the Commission on behalf of the seller. One comment noted that the regulations do not permit a seller's designee to serve similar notice to purchasers. The comment suggested the burden of excess paperwork would be eliminated on co-owners of a well by allowing an operator to serve notice on behalf of more than one co-owner. The Commission agrees and therefore is amending § 273.103 to allow a seller's designee to serve notices of intent to make interim collections. In addition, a corresponding revision is being made to § 270.202(b)(2)(ii) to waive the obligation of a reseller to notify a purchaser when a reseller's designee under § 273.103 has served a purchaser with such a notice of intent. These revisions maintain the Commission's existing policy of allowing a seller's designee to make filings and notices required by Part 273.

(D) *Refund Requirements of § 273.302.*

(1) *Refund Obligations.* The present § 273.302(b) provides that any filing for an interim collection under Part 273 shall have the effect of a general undertaking to comply with the refund provisions of that part. In the Notice of Proposed Rulemaking, the Commission proposed to amend the rule by making an interim collection itself (and not the interim collection filing with the Commission) constitute the general undertaking to comply with the refund provision. Since under the new rule an interim collection filing will be required only for gas subject to Natural Gas Act rate schedules, it is necessary to impose the refund obligation on interim collections themselves for all gas, rather than on interim collection filings. Comments raised no objection to the proposed change. The Commission therefore revises § 273.302(b) accordingly.

(2) *Refunds and refund reports.* Section 273.302 presently requires a refund to be made to the purchaser within forty-five (45) days of a final determination that a well is not eligible for the price collected in an interim collection, and a refund report to be submitted to the Commission within thirty (30) days after the making of the refund. The Notice of Proposed Rulemaking proposed to require a filing of a refund report within seventy-five (75) days of the date of an unfavorable determination or the date of withdrawal of an application for an eligibility determination.

One comment advocated exempting small producers from the refund reporting requirements of § 273.302. Producers selling under small producer certificates are subject to the requirements of these sections, including the reporting provisions. The filing of refund reports is necessary to ensure compliance with the NGPA and the correct refunding of amounts which were paid in the interim collection process. No distinction between large and small producers is appropriate.

Comments asserted that both the forty-five (45) and seventy-five (75) days time periods were insufficient to compile the information required to make appropriate refunds and submit reports. To reduce these time pressures the Commission is extending both deadlines. Appropriate refunds will not have to be made within sixty (60) days after the date of a final determination that a well is not eligible for the price category stated in the application for determination, or the date of a withdrawal of an application for an eligibility determination. A refund report will be due ninety (90) days from either of these two events.

The proposal also included a new requirement to file a statement that no refunds are due if such is the case. Comments contested this requirement. The Commission, however, believes that such a statement is necessary to the compliance program. Therefore, when no refund is due following a determination that a well is not eligible for the price category stated in the application for determination, or where an application for a determination has been withdrawn from before the Commission or a jurisdictional agency, sellers will be required to file a statement to that effect.

The present regulations require the refund report to state separately the principal amount of overpayment required to be refunded and the appropriate interest paid on this amount. As amended, § 273.302(f)(1) (iii) and (iv) requires the following additional information to be included: the well name, the American Petroleum Institute Well Number if existent, the jurisdictional agency with which the application for determination was filed, and, if applicable, the date of withdrawal of the application. The report also must specify the due dates for any refunds, the actual dates of payment of any refunds, and the time period covered by each refund. The report must state separately the amount that must be refunded, and the appropriate amount of interest attributed to the refund. Submission of such information is necessary to enable the Commission to fulfill its obligations under the NGPA to ensure proper refund payments. A refund report will be allowed to contain information for more than one well so long as the information is submitted on a well-by-well basis.

(3) *Refund Payment by Cash or Check.* Section 273.302(e)(2) presently provides that refunds shall be paid by cash or check. This provision was retained in the Notice of Proposed Rulemaking. Comments were received stating that amounts due as refunds should be credited to current billings if purchasers agree, in order to reduce paperwork for both sellers and purchasers.

The Commission has decided to retain the present rule. Working off a refund through credits to current billings would be harder to verify for compliance purposes than would be a lump sum payment. The Commission desires to maintain its policy as stated in Order No. 36 of attempting to ensure that overcharges be returned to purchasers as quickly as possible.

(4) *Concurrence of the Purchaser.* Section 273.302(e)(3)(ii) presently requires that a refund report contain a release from the purchaser showing that refunds have been paid. The Notice of Proposed Rulemaking contained a similar provision which would require a statement of concurrence in the filing by the purchaser. Various comments stated that pipelines often do not give their written concurrence to producers in an expedited manner. These comments proposed that a deadline should be imposed on a pipeline to register its concurrence or nonconcurrence. The Commission will alleviate this problem by altering the filing requirements in the new § 273.302(f)(4). A refund report will be permitted to be filed by a seller with a statement that a purchaser's concurrence has not been received. In this circumstance, the amendments now require the purchaser to submit to the Commission the concurrence, or the reason for its refusal to submit its concurrence to a seller. This submission

will be due within thirty (30) days of a seller's filing a refund report or statement with the Commission which does not include the purchasers concurrence. A duplicate of the submission shall be served upon the seller.

(E) *Reseller Rules.*

Section 270.202(b)(1)(ii) presently provides that a reseller is subject to the same refund conditions under Part 273 as the person who sold the natural gas to the reseller.

However, the present § 270.202(b)(2) waives the reseller's filing obligations under Part 273 if the filings have been made by certain other persons or entities, including the person or entity who sold the gas to the reseller. This provision by implication was interpreted by some commenters to refer to the refund filing requirements of § 273.302.

The Commission believes that because the reseller is responsible for making the refund the reseller also should be required to file a refund report under § 273.302 regardless of whether a refund report is also filed by another person or entity, including the person or entity who sold the gas to the reseller. The Commission did not intend the refund report requirement to be waived by §270.202(b)(2). Therefore, to clarify the regulations, the waiver of § 270.202(b)(2) is amended to be limited specifically to interim collection filings required under §§ 273.202 and 273.203.

The nature of several of the comments indicated that many parties are confused regarding a reseller's obligations where the reseller has purchased gas under a percentage-of-proceeds contract. In certain circumstances, a sale to reseller in a percentage-of-proceeds sale is not treated as a first sale for purposes of Subchapter H (other than Part 270). (See § 270.202(h).) In such circumstances the person who sold the gas to the reseller would have no obligation to make any interim collection filings or serve any notices required in §§ 273.202 and 273.203. Those obligations, therefore, would rest with the reseller. Section 270.202(b)(1)(ii) subjects the reseller to all refund obligations including any refund report or statement that must be made.

Interim and retroactive collection filing requirements apply only to first sales. Since a percentage-of-proceeds sale to a reseller is not treated as a first sale by § 270.202(h), the person selling to the reseller is not subject to the refund conditions in §§ 270.202(b)(1)(ii) and 273.302. Therefore, where a percentage-of-proceeds sale to a reseller occurs and the reseller subsequently makes a first sale that necessitates interim collections, the reseller will incur the refund obligation and reporting requirements.

One comment suggested the Commission state that a reseller and a behind-the-plant seller may contractually agree that the reseller shall distribute proceeds attributable to interim collections to the behind-the-pipe seller prior to the rates in the application for determination becoming final. No amendment is necessary since this suggestion presently is permitted in the current regulations.

(F) *Waiver of Pending Reports.*

One comment suggested that the proposed retroactive collection filing and notice provisions should be made applicable immediately upon issuance of the rule. If the regulations amended by this rule remain in effect for thirty days, reports the Commission has decided are unnecessary will continue to be filed during those thirty days. The comment applies equally to certain interim collection filings. The Commission agrees with this suggestion. The reduction of interim and retroactive filing requirements shall become effective immediately.

(G) *Evidentiary Submissions by Pipelines.*

Section 154.94(i)(2)(ii) requires an evidentiary submission by a pipeline within sixty (60) days of a pipeline's receipt of service of a change in rate by a jurisdictional producer through either an interim collection under Part 273 or a blanket affidavit under § 154.94(h) for collection of a maximum lawful price under certain enumerated sections of the NGPA. This requirement only applies where the gas is subject to the

Natural Gas Act. One comment pointed out that § 154.94 should be amended to reflect that alternatively, an evidentiary submission must be filed within sixty (60) days from the day of receipt of service of a copy of a retroactive collection report. The comment urges this clarification to clear up any uncertainty regarding the filing deadline.

The Commission agrees. Failure to mention retroactive collection was inadvertent. Section 154.94 has been amended to require a pipeline to file an evidentiary submission within sixty (60) days of receipt of service of a retroactive collection filing.

(5) Miscellaneous Comments.

One comment questioned whether a pipeline is permitted to pay a producer pursuant to a notice of interim collection without first verifying that a producer made an appropriate filing with the Commission. The Commission believes the regulations allow a pipeline or other purchaser to rely solely on the notice from a seller to commence interim collection payments.

One comment requested that the thirty (30) day notice requirement for a change in rate under section 4(d) of the Natural Gas Act be waived to allow immediate interim collection for the price filed in the application for determination before a jurisdictional agency. The Commission already has established this waiver of § 154.94(i)(1) of the regulations.

Other miscellaneous suggestions were made regarding such issues as the interim collection time period limitation at § 273.202, the period a seller must wait after obtaining a final determination of eligibility before initiating retroactive collections at § 273.203, collections for deliveries which occurred prior to the date the application was filed, and the Federal Register notice of application. These suggestions were considered in prior rulemakings and were not adopted. No new information was submitted which convinces us to amend the regulations as suggested.

III. Summary of Amendments

The following amendments and clarifications have been made to the final regulations:

Section 154.94(i) has been amended to provide that an evidentiary submission must be submitted within sixty (60) days of the latest of an interim collection or retroactive collection notice or receipt of a filing pursuant to § [illegible](h)(6).

Section [illegible] has been amended to provide that a reseller is not obligated to make an interim or retroactive collection filing or notify a purchaser of an intent to make an interim collection if either such filing or notice has been made by the person who sold the gas to the reseller, or by the reseller's designee. However, a reseller must file a refund report even if a report was filed by either of these parties.

Section 273.103(d)(1) has been amended to provide that a seller's designee will be allowed to serve any notice required by Part 273 in lieu of the seller serving such notice.

New cross references are listed under § 273.104(b) for a special interim collection rule for certain applications for stripper well determinations and for a special rule ceasing the right to make an interim collection upon withdrawal of an application for determination before the Commission.

A seller making an interim or retroactive collection for gas subject to the Commission's jurisdiction and subject to a Natural Gas Act rate schedule on file with the Commission must file with the Commission notice of such collection for each category of gas sold in each rate schedule.

Section 273.202(e) has been amended to provide that interim collections can be made for the sale of gas which has already been subject to interim collections as long as the gas has previously received an affirmative determination from a jurisdictional agency.

The undertaking of an interim collection shall give rise to an obligation to make any appropriate refund under § 273.302(b).

Escrow provisions for refund assurance in § 273.302(c) have been redesignated as § 273.202(d)(2).

Under § 273.302(e), a refund report will now be due within 90 days from the day a negative determination becomes final or an application for determination is withdrawn. Refunds must be paid within 60, rather than 45 days, of the final negative determination or withdrawal.

New detailed information required in a refund report is enumerated in § 273.302(f)(1). A single report under § 273.302(f)(2) may contain refund data for more than one well, if identified on a well-by-well basis.

A seller may indicate a purchaser's nonconcurrence in a refund report if a statement of concurrence is not received by the seller that all proper refunds have been made. In such an instance, the purchaser shall submit to the Commission, within 30 days of receipt of a copy of a seller's refund report or statement, its reason for refusing to submit its concurrence to the report with the seller.

IV. Public Procedure and Effective Date

Amendments to Part 273 were initially proposed for comment on May 7, 1980, 45 FR 31418 (1980). Comments were received until June 16, 1980. A public hearing on the proposed rulemaking was held on July 16, 1980. By this process the Commission complied with the provision of section 502(b) of the NGPA which requires that "[t]o the maximum extent practicable, an opportunity for oral presentation of data, views, and arguments" to be afforded for certain regulations under the NGPA. The amendments to Parts 154, 270, and 273 contained in this order rest upon consideration given to the information received during the comment and hearing process. Therefore, the Commission believes that no further notice of public procedure is required under 5 U.S.C. 553.

The amendments to §§ 273.202, 273.203 and 273.204 relieve restrictions and pursuant to section 553 of the Administrative Procedure Act (5 U.S.C. 552), shall be made effective immediately. All other amendments shall be effective March 16, 1981.

(Natural Gas Act, as amended, 15 U.S.C. § 717, et seq., Department of Energy Organization Act, 47 U.S.C. §§ 7701-7352; E.O. 12009, 42 FR 46267; Natural Gas Policy Act of 1978, 15 U.S.C. § 3301-3432, Administrative Procedure Act, 15 U.S.C. § 553.)

In consideration of the foregoing, the final regulations of Parts 154 of Subchapter E, and Parts 270 and 273 of Subchapter H, Chapter I of Title 18, Code of Federal Regulations, are amended as set forth below. The amendments to §§ 273.202, 273.203 and 273.204 are effective immediately. All other amendments shall be effective March 16, 1981.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,237]

46 F. R. 14118 (February 26, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Texas-7)]

High-Cost Gas Produced From Tight Formations; Final Rule

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which

may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Texas Railroad Commission that the Lower Wilcox Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: February 19, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8307, or John Bassett, (202) 357–8657/Ting Chin (202) 357–8769.

Before Commissioners: Georgiana Sheldon, Acting Chairman; Matthew Holden, Jr., and George R. Hall.

High-Cost Gas Produced From Tight Formations; Docket No. RM79–76 (Texas–7); Order No. 133; Final Rule.

Issued February 19, 1981.

The Commission hereby amends § 271.703(d) of its regulations to include the Lower Wilcox Formation as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued December 19, 1980 (45 FR 85779, December 30, 1980)[1] based on a recommendation by the Railroad Commission of Texas (Texas) in accordance with § 271.703(c), that the Lower Wilcox Formation be designated as a tight formation.

Evidence submitted by Texas and the commenters supports Texas' assertion that the Lower Wilcox Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Texas recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432; Administrative Procedure Act, 5 U.S.C. 553.)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective February 19, 1981.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,238]

46 F. R. 14119 (February 26, 1981)

18 CFR Part 375

[Docket No. RM81–14; Order No. 132]

Delegation of the Commission's Authority to the Director of the Office of Electric Power Regulation

February 13, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Commission is delegating to the Director of its Office of Electric Power Regulation authority to take action on competing applications for preliminary permits for water power projects. The Director may act only if applications are uncontested by persons other than the applicants and if the plans of development are not significantly different. This rule will reduce the number of applications on which the Commission must act directly and thereby help expedite the hydropower licensing procedures.

EFFECTIVE DATE: February 13, 1981.

FOR FURTHER INFORMATION CONTACT: Ronald Corso, Director, Division of Hydropower Licensing, Office of Electric Power Regulation, 825 N.

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[1] Comments were invited and two were received. No party requested a public hearing in this matter and no hearing was held.

Capitol Street, NE., Washington, D.C. 20426 (202) 376-9171.

Peter Lefkin, Office of the General Counsel, 825 N. Capitol Street, NE., Washington, D.C. 20426 (202) 357-8607.

Before Commissioners: Georgiana Sheldon, Acting Chairman; Matthew Holden, Jr., George R. Hall and J. David Hughes.

Delegation of the Commission's Authority to the Director of Office of Electric Power Regulation; Docket No. RM81-14; Order No. 132; Final Rule.

I. Background

On August 14, 1978, the Commission adopted Delegations of Authority [Phase I], 43 FR 36433, which served to transfer to staff over 7,000 decisions annually of a largely ministerial nature, in order to free the Commission's time for issues of greater importance. Subsequently, on July 23, 1979, the Commission added to these delegations by adopting additional ones, in the Phase II Delegation, Docket No. RM79-59, 44 FR 46449 (August 8, 1979).

As a continuation of this process, the Commission has decided to approve a further delegation of authority to the Director of the Office of Electric Power Regulation to take action on competing applications for preliminary permits authorized under sections 4(f), 5, and 7 of the Federal Power Act. This delegation was prompted by the Commission's determination that an inordinate amount of the Commission's time is spent on matters that do not require the attention of the full Commission. At the time of this order, there exist nearly 800 applications for preliminary permits pending before the Commission. Of the pending applications, over 50 percent are competing applications for the same hydropower sites. This delegation will permit the Director of the Office of Electric Power Regulation to deal with uncontested competing preliminary permit applications and thereby enable the Commission to focus on more complicated and controversial tasks.

Under the delegation of authority, the Director will apply § 4.33(g) of the Commission's regulations to determine which of the competing applicants will receive a preliminary permit. The Director will be authorized, among other things, to carry out the state/municipal preference provisions of the Federal Power Act where one of the competing permit applicants is a municipality or state and its competitor is a non-public entity, provided that the applications are not materially different.

In general, the matter being delegated requires limited discretionary decision making on the part of the Office Director, whose authority is qualified by § 1.7 of this chapter which enables "any interested person" to appeal to the Commission the Director's decision.

This rule is based upon the authority granted the Commission in section 401(f) of the Department of Energy Organization Act (42 U.S.C. 7171(f)) "to establish such procedural and administrative rules as are necessary to the exercise of its functions."

II. Summary of the Rule

Section 375.308 is amended by revising paragraph (k) to grant to the Director of the Office of Electric Power Regulation authority to act on both uncontested applications for preliminary permits where no competing application is filed and on competing applications submitted by more than one applicant for water power projects that are mutually exclusive, provided the applications are uncontested (for purposes of this delegation, intervention by a competing applicant will not result in a contested application) and do not propose materially different plans to develop the site for hydroelectric power.

III. Effective Date

The Commission waives the notice and comment provisions of the Administrative Procedures Act, 5 U.S.C. 553(b), because the rule is one of agency procedure and practice. Public procedure is therefore unnecessary. In addition, the Commission finds good cause to make the rule effective immediately, pursuant to 5 U.S.C. 553(d).

Preliminary permit applications are currently being submitted in increasing numbers due to the renewed interest in hydropower development. The Commission received 76 such applications in 1979, 501 in 1980, and the rate of submittal is even greater thus far in 1981. Of the 787 applications on file on February 6, 1981, a substantial number are competing applications for mutually exclusive sites. This delegation will permit quicker issuances of preliminary permits in those cases where the applications are uncontested other than by the competing applicants themselves. More efficient discharge of the Commission's responsibilities is in the public interest.

In consideration of the foregoing, Chapter I of Title 18, Code of Federal Regulations, is amended as set forth below, effective on the date of issuance.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,239]

46 F. R. 15498 (March 6, 1981)

18 CFR Part 282

[Docket No. RM79-21]

Alternative Fuel Price Ceilings for Incremental Pricing Under the Natural Gas Policy Act of 1978

AGENCY: Federal Energy Regulatory Commission.

ACTION: Interim Rule.

SUMMARY: The Commission revises on an interim basis the methodology for calculating the monthly alternative fuel price ceilings for state regions. Under the revised methodology, the applicable alternative fuel price ceiling published on the twentieth of each month for each of the contiguous states shall be the lower of the alternative fuel price ceiling for the state or the alternative fuel price ceiling for the multistate region in which the state is located. In addition, § 282.404(a) of the Commission's regulations is amended by adding subparagraph (4) making effective March 1981 prices that were changed as a result of the newly revised methodology. Such prices supersede those corresponding state prices published on February 20, 1981.

DATES: Effective March 2, 1981.

Written comments by April 13, 1981. Requests for oral hearing by March 13, 1981.

ADDRESS: Office of Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, Reference Docket No. RM79-21.

FOR FURTHER INFORMATION CONTACT:

Thomas P. Gross, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8171.

Sandra Delude, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-5522.

Interim Rule

Issued: March 2, 1981.

I. Introduction

The Federal Energy Regulatory Commission (Commission) is amending, on an interim basis, its regulations on incremental pricing (18 CFR Part 282) under Title II of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3301-3432). Specifically, § 282.404(a) is amended by adding subparagraph (4) to provide that the alternative fuel price ceilings for March 1981, listed in new § 282.404(a)(4), supersede the corresponding state ceilings published on February 20, 1981. In addition, this order provides that the alternative fuel price ceilings published on the twentieth of each month following February 1981, for each of the 48 lower contiguous states shall be the lower of:

(1) the alternative fuel price ceiling applicable to the state; or

(2) the alternative fuel price ceiling applicable to the multistate region in which the state is located.

II. Background

Title II of the NGPA requires the Commission to prescribe and make effective a program of incremental pricing of natural gas which is used as industrial boiler fuel. Section 204(e) of the NGPA directs the Commission to establish ceilings on gas prices charged to incrementally priced users, based on the cost of alternative fuel oils in each region designated by the Commission.

The Commission's current regulations implementing the incremental pricing program establish two sets of regions: (1) 48 regions, each region being one of the 48 contiguous states; and (2) eight multistate regions, labeled Regions A through H. The 48 state regions are used to calculate alternative fuel price ceilings which are published each month in the **Federal Register** on or before the twentieth day of the month preceding their effective date. In addition as provided in Appendix I to Subpart D of Part 282, the multistate regions may be used by the Commission in deriving alternative fuel price ceilings for state incremental pricing regions (1) for which statistically valid samples of oil prices may be unavailable, or (2) where the Commission determines that the public interest requires use of the regional ceiling in place of the state ceiling. The price ceiling for each region (state or multistate) is calculated by a formula which uses the price of high-sulfur No. 6 fuel oil observed in that region during a previous period. The collection of data, the application of the formula, and the publication of the ceilings are performed by the Energy Information Administration (EIA) in accordance with Commission direction.

The Commission recently instituted a rulemaking proceeding in Docket No. RM79–21 for the purpose of re-examining both the designation of the incremental pricing regions and the methodology for calculating the price ceilings in those regions. On November 4, 1980, a Notice of Inquiry was issued in this docket (45 FR 74505, November 10, 1980), requesting public comment on possible revisions to the current regions and methodology. More than 50 written comments were filed. In addition, members of the public were given an opportunity to discuss the Notice of Inquiry in informal technical conferences held in Kansas City, Missouri, on November 21, 1980 and in Washington, D.C., on November 24, 1980, and January 6, 1981.

III. Discussion

Studies made by the Commission staff demonstrate that substantial pricing disparities exist in the price ceilings for neighboring states and that the impact of such disparities is increasing as the cost of high-sulfur No. 6 fuel oil rises.[1] The disparities may be due to actual oil price differences in neighboring states, too few oil transactions, or some other factor or combination of factors. (The EIA is continuing to study the methodology for calculating the price ceilings program in an attempt to discern the reason for the disparities.)

As the Commission noted in the Notice of Inquiry, these disparities increase the possibility of industrial users' switching from natural gas to fuel oil purchased in a nearby state. In addition, substantial pricing disparities create inequities, in that industrial gas users in different states, but within the same marketing area, may pay substantially different prices for natural gas. As a result, the Commission has determined to issue an interim rule amending the existing methodology in order to discourage potential fuel switching.

Written and oral comments submitted in response to the Notice of Inquiry generally indicated that the current alternative fuel price ceilings are working as well as possible and that many of the changes discussed in the Commission's Notice of Inquiry would only aggravate existing problems and inject uncertainty and instability into the Commission's current incremental pricing program. The commenters urged the Commission to retain the basic regulatory structure now in effect, but to add some flexibility to the methodology to correct price ceilings which do not accurately reflect current market prices.

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[1] *See*, Rule Adopting Revised Alternative Fuel Price Ceilings for the State of Kentucky, Docket No. RM81–9, issued December 24, 1980 (46 FR 2036).

One of the most commonly proposed additions to the current methodology was a fail-safe mechanism under which a non-exempt user of natural gas could reduce the applicable incremental pricing surcharge to a lower alternative fuel price if the user could certify to the Commission that the lower alternative fuel price is available to the facility.

Other comments proposed alternative mechanisms, such as the "contiguous state approach" or the multistate regional approach." Under the contiguous state approach, the price ceiling would be the lowest price ceiling in any state contiguous to the state in question if lower than the otherwise applicable state price ceiling. Under the multistate regional approach, the price ceiling would be the lower of the price ceiling applicable to the mutistate region in which the state is located, or the alternative fuel price ceiling which would otherwise be applicable to the state.

The Commission agrees that some flexibility should be added to the current methodology. The Commission has considered the fail-safe mechanism in some detail during the initial implementaton of the incremental pricing program and in conjunction with this rulemaking. It believes that such a mechanism would be difficult to implement at this time. As proposed in the comments, the price ceiling in a facility-by-facility fail-safe mechanism is subject to potential manipulation. Administrative problems also exist with respect to verification of the availability of a lower price and correction, if the price certified is found to be incorrect. The contiguous state approach, while providing flexibility, would raise issues relating to an appropriate definition of "contiguous." However, the multistate regional approach would provide the needed flexibility without presenting either the definitional problems of the contiguous state approach or the administrative problems of the fail-safe mechanism. Accordingly, the Commission is adopting the multistate regional approach in this rulemaking. The implementation of the multistate regional approach will result in some, but not a large, reduction in total MSAC's (maximum surcharge absorption capability).[2] However, the Commission believes that the reduction is outweighed by the benefits provided by increased flexibility and improved accuracy in the price ceilings.

Specifically, the methodology for calculating the altenative fuel price ceilings is revised to provide that the alternative fuel price ceilings for each of the 48 contiguous states shall be the lower of (1) the alternative fuel price ceiling applicable to the state, or (2) the alternative fuel price ceiling applicable to the multistate region in which the state is located.

Three other proposals which were discussed in the Notice of Inquiry were, (1) the grouping of No. 2 and No. 6 fuel oil prices, (2) the cumulative decrement approach, and (3) sixteen proposed multistate regions. Virtually all of the comments opposed the first two proposals, and the Commission declines to adopt either of these methods as more practicable than the system already in effect. The comments were divided, however, as to whether the Commission should adopt the sixteen proposed regions or retain the current 48 state and eight multistate regions. None of the comments offered any compelling reasons to adopt the sixteen-region approach. Therefore, rather than subject the current methodology to additional confusion and uncertainty, the Commission has decided to retain the existing 48 state and eight multistate regions at this time.

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[2] The exact amount of MSAC reduction is difficult, if not impossible, to quantify. The Commission has analyzed prices in the nine states (Pennsylvania, Georgia, California, Illinois, Indiana, Michigan, New Jersey, New York and Ohio) which contain approximately two-thirds of all facilities subject to incremental pricing. For the five-month period of October 1, 1980, through February, 1981, seventeen of the forty-five published prices would have been reduced had the rule adopted herein been in effect. The amounts involved are noticeable, but do not appear to be of a magnitude that would outweigh the advantages of this adjustment.

The Commission also recognizes that certain individual or state-wide circumstances may exist in which some type of relief or adjustment from the methodology adopted in this rule may be appropriate. The Commission will continue to review any such situations on a case-by-case basis and to administer relief, where appropriate, by means of staff adjustments pursuant to section 502(c) of the NGPA or by rulemaking.

The Commission also notes that the EIA continues to study various methodologies which may eventually prove to be useful in calculating appropriate alternative fuel price ceilings. The Commission has been informed that one such methodology has shown promise and is currently being evaluated. When detailed information and data on this method become available from the EIA, the Commission will consider such material.

IV. Summary of the Interim Rule

As discussed above, the Commission has determined that the alternative fuel price ceiling for each of the 48 contiguous state regions should be the lower of either the ceiling calculated for that state or the ceiling calculated for the multistate region in which the state is located. In order to implement this decision for the month of March 1981, for which alternative fuel price ceilings were published on February 20, 1981, the Commission is amending § 282.404(a) of its regulations by adding new subparagraph (4). Subparagraph (4) lists the ceilings for March 1981 which shall supersede those previously published on February 20, 1981; that is, it lists the appropriate multistate regional ceilings for each state in which the multistate regional ceiling for March 1981, is lower than the state regional ceiling. To implement this methodology for months following March 1981, the Commission is directing its Executive Director to direct EIA to publish as the alternative fuel price ceilings applicable to each state region for months following March 1981, the lower of either the ceiling calculated for that state or the ceiling calculated for the multistate region in which the state is located.

V. Effective Date

The Commission believes that this rule will promote equity and discourage potential fuel switching. Accordingly, the Commission finds that good cause exists in accordance with 5 U.S.C. 553 (b) and (d) to make this rule effective immediately as an interim rule, applicable to all alternative fuel price ceilings for the month of March 1981, and thereafter, until the Commission issues a final rule in this docket. The Commission will afford an opportunity for interested persons to present views and comments, as set forth below.

VI. Comment Procedures

A. *Written Comments.* Interested persons are invited to submit written comments, data, views, or arguments with respect to this interim rule. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, and should reference Docket No. RM79-21. An original and 14 copies should be filed. All comments received prior to 4:30 p.m. EST, April 13, 1981, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection through the Commission's Division of Public Information, Room 100, 825 North

Capitol Street, NE., Washington, D.C., during regular business hours.

B. *Public Hearing.* Interested persons may request the opportunity for an oral presentation of their views at a public hearing. Requests for an oral hearing should be submitted no later than March 13, 1981, to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, and should reference Docket No. RM79-21. If any requests are received by that time, the hearing will be held on March 23, 1981, at the above address, and will be announced by March 18, 1981.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301 *et seq.*; Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; E.O. 12009, 42 CFR 46267 (1978))

In consideration of the foregoing, the Commission amends Subpart D, Part 282, Subchapter I, of Chapter I, Title 18 of the Code of Federal Regulations, on an interim basis, as provided below, effective upon issuance.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,240]

46 F. R. 16256 (March 12, 1981)

18 CFR Part 282

[Docket No. RM80-62]

Section 206(d) Exemption for Mechanical Cogeneration Facilities From the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978; Effective Date and Availability of Exemption Affidavits

Issued: March 2, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Effective Date and Availability of Exemption Affidavits.

SUMMARY: On October 23, 1980, the Federal Energy Regulatory Commission (Commission) issued a rule (45 FR 71787, October 30, 1980) under Title II of the Natural Gas Policy Act of 1978 (NGPA) providing an exemption from incremental pricing surcharges for natural gas used in mechanical cogeneration facilities. The rule was transmitted to Congress for review as required by section 206(d) of the NGPA.

During the period for Congressional review set forth in section 507(b) of the NGPA, neither House disapproved the submittal. The exemptive rule thus became effective on March 1, 1981, the day following expiration of the review period.

EFFECTIVE DATE: March 1, 1981.

FOR FURTHER INFORMATION CONTACT: James Liles, Office of Regulatory Analysis, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357-8158.

SUPPLEMENTARY INFORMATION: Affidavits for claiming an exemption from incremental pricing have been revised to reflect the mechanical cogeneration exemption and are available through the Commission's Division of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426. By order issued March 2, 1981, the Commission waived its regulations in § 282.204(d)(7) [18 CFR Part 282] (46 FR 15879, March 10, 1981) to provide that if the owner or operator of an industrial boiler fuel facility files, by March 25, 1981, an affidavit with the Commission claiming a mechanical cogeneration exemption, and sends a copy to the facility's natural gas supplier, the facility shall be exempt from incremental pricing as of March 1, 1981.

Kenneth F. Plumb,
Secretary.

[¶ 30,241]

46 F. R. 19229 (March 30, 1981);
46 F. R. 32238 (June 22, 1981)

18 CFR Part 292

[Docket No. RM81-2; Order No. 135]

Eligibility, Rates, and Exemptions for Qualifying and Utility-Owned Geothermal Small Power Production Facilities

Issued: March 23, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts a final rulemaking regarding eligibility, rates, and exemptions for qualifying and utility-owned geothermal small power production facilities. The Order implements the Energy Security Act amendments to the Federal Power Act and the Public Utility Regulatory Policies Act of 1978 concerning geothermal small power production facilities by amending Part 292 of the Commission's rules. Except with respect to the Public Utility Holding Company Act, this rulemaking implements the Energy Security Act amendments, only as they relate to geothermal small power production facilities of which a utility owns 50 percent or less.

EFFECTIVE DATE: May 1, 1981.

FOR FURTHER INFORMATION CONTACT:
Glenn Berger, Office of the General Counsel, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8033,
or
Michael Kessler, Office of the General Counsel, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8033.

SUPPLEMENTARY INFORMATION:

In the matter of small power production and cogeneration facilities—eligibility, rates, and exemptions for qualifying and utility-owned geothermal small power production facilities.

On November 6, 1980, the Federal Energy Regulatory Commission (Commission) issued a Notice of Proposed Rulemaking (NOPR)[1] which proposed rules to implement section 643 of the Energy Security Act of 1980 (ESA).[2] The ESA amended the Federal Power Act (FPA) and the Public Utility Regulatory Policies Act of 1978 (PURPA) by adding provisions relating to geothermal small power production. Except with respect to the Public Utility Holding Company Act (PUHCA) (15 U.S.C. 79), this rulemaking implements the ESA amendments only as they relate to geothermal small power production facilities of which a utility owns less than 50 percent. The ESA amendments relating to utility-owned geothermal small power production facilities will be the subject of a subsequent rulemaking.

I. Background

Section 201 of PURPA authorizes the Commission to prescribe rules under which small power production facilities and cogeneration facilities can obtain "qualifying" status and thus become eligible for the rates and exemptions set forth in the Commission's rules implementing sections 201 and 210 of PURPA.[3] Section 643(a) of the ESA is intended to clarify the authority of the Commission to classify geothermal resources as a "primary energy source" for the purpose of eligibility as a qualifying small power production facility under section 3(17)(A) of the FPA, as amended by section 201 of PURPA.[4]

Section 643(b) of ESA contains three amendments to section 210 of PURPA. Subsection 643(b)(1) amends section 210(a) of PURPA. Section 210(a) requires the Commission to prescribe rules necessary to encourage cogeneration and small power production. The ESA amendment to this section requires the Commission to prescribe rules to encourage "geothermal small power production facilities of not more than 80 megawatts capacity."

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[1] 45 FR 74934 (1980).

[2] Pub. L. No. 96-294, 94 Stat. 611 (1980).

[3] Order No. 69, 45 FR 12214 (Feb. 25, 1980). Order No. 70, 45 FR 17959 (Mar. 20, 1980).

[4] It is the Commission's position that, even before the ESA amendments, geothermal facilities were eligible for qualification as small power production facilities. This view is based on the legislative

Section 643(b)(2) of ESA amends section 210(e)(1) of PURPA to authorize the Commission to exempt "geothermal small power production facilities of not more than 80 megawatts capacity" from the FPA, the PUHCA, and State laws and regulations respecting the rates or the financial or organizational regulation of electric utilities, if the Commission determines such exemption is necessary to encourage cogeneration and small power production. Under this amendment, the Commission's exemptive authority is no longer limited to "qualifying" geothermal small power production facilities. Therefore, the Commission may exempt utility-owned geothermal small power production facilities (UGSPPF) from these laws and regulations.

Prior to amendment, section 210(e)(2) of PURPA limited the Commission's authority to exempt qualifying small power production facilities to those with a capacity of 30 megawatts or less.[5] Section 643(b)(3) of ESA increases the limit to "80 megawatts for a qualifying small power production facility using geothermal energy as the primary energy source * * *." Thus, the Commission may exempt any qualifying small power production facility using geothermal energy as the primary energy source from the laws and regulations specified in section 210(e)(1) of PURPA.

The NOPR also discussed exempting UGSPPFs from the laws, and regulations specified in section 210(e)(1) of PURPA, as well as extending the "avoided cost" rate to such facilities pursuant to section 210(a). Public comments addressing this proposal generally supported the exemption of UGSPPFs from the PUHCA. Comments were divided, however, regarding exemption of UGSPPFs from the remaining laws and regulations. In order to have more time to consider the latter comments, the Commission has decided to implement the ESA amendments to the FPA and PURPA concerning geothermal small power production in two rulemakings.

This rule implements the ESA amendments to the FPA and PURPA concerning qualifying geothermal small power production facilities. It also exempts UGSPPFs from the PUHCA. In a subsequent rulemaking the Commission will consider further the implications of exempting UGSPPFs from the FPA, and certain State laws. The Commission does not yet reach the issue of extending the "avoided cost" rate principals to such facilities.

The Commission received thirteen comments in response to the NOPR in this docket and has considered all the comments in the formulation of the final rule.

II. Section-by-Section Analysis

§ *292.204 Primary energy source.*

Section 3(17)(A) of the Federal Power Act, as amended by section 201 of PURPA, defines a "small power production facility" as a facility which produces energy solely by the use, as a primary energy source, of biomass, waste, renewable resources, or any combination thereof, and which has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), is not greater than 80 megawatts. The amendment contained in section 643(a)(1) of ESA states that geothermal resources are an eligible

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history of PURPA. 125 Cong. Rec. S. 17808 (daily ed. October 9, 1978) (remarks of Senators Durkin and Jackson). The conference report of the ESA indicates that the legislation does not intend "to cast the FERC's present regulations under section 3(17) into doubt by reason of this amendment." S. Rep. No. 96-824, 96th Cong., 2nd Sess. 312 (1980).

[5] Small power production facilities between 30 and 80 megawatts which use biomass as a primary energy source are exempt from the Public Utility Holding Company Act, and from State laws respecting the (wholesale) rates or financial or organizational regulation. See § 292.602 of the Commission's rules.

primary energy source for small power production facilities.

Section 292.204 of the Commission's rules sets forth criteria for qualifying small power production facilities. To reflect the changes required by section 643(a)(1) of ESA, the Commission is amending this section of its rules to make it clear that small power production facilities using geothermal resources as a primary energy source can be qualifying facilities. This change appears in § 292.204(b)(1)(i), where "geothermal resources" is added to the list setting forth the eligible primary energy sources of a qualifying small power production facility.

§ 292.202 Definitions.

The Commission is amending § 292.202 of its rules by adding a new paragraph (o) which defines "utility geothermal small power production facility" (UGSPPF) as a small power production facility which uses geothermal energy as the primary energy source, and of which more than 50 percent is owned either (1) by an electric utility or utilities, electric utility holding company or companies, or any combination thereof, or (2) by any company 50 percent or more of the outstanding voting securities of which are directly or indirectly owned, controlled, or held with power to vote, by an electric utility, electric utility holding company, or any combination thereof.

The proposed rule defined a "utility geothermal small power production facility as a * * * facility * * * of which an electric utility * * * owns more than 50 percent of the outstanding voting securities." Several commenters noted that it is not the facility which issues securities. The commenters correctly pointed out that a UGSPPF is an asset of a corporation, and it is the corporation which issues securities. The Commission agrees with the commenters and has redefined a UGSPPF to reflect the ownership arrangements between a utility and a geothermal small power production facility.

§ 292.601 Exemption of qualifying facilities from the Federal Power Act.

This section implements section 210(e)(2) of PURPA as amended by section 643(b)(3) of ESA. The ESA permits the Commission to exempt qualifying small power production facilities of up to 80 megawatts capacity using geothermal resources from regulation under the FPA, the PUHCA, and from State laws and regulations respecting rates or the financial or organizational regulation of electric utilities.

Section 292.601 of the Commission's rules is amended by increasing the size limitation for exemptions from the FPA from 30 to 80 megawatts for qualifying small power production facilities using geothermal energy as a primary energy source.

Under the proposed rule a UGSPPF was added to the definition of "qualifying facility" and thus was eligible for exemption from the FPA, the PUHCA, and from State laws and regulations respecting rates or the financial or organizational regulation of electric utilities. The proposed rule also discussed extending the "avoided cost" rate benefits of section 210(a) to a UGSPPF.

The comments filed by the State regulatory authorities and non-utility owners regarding this provision opposed extending the rate and exemption benefits to UGSPPFs. Some of these commenters argued that the Commission lacks the statutory authority to extend the PURPA section 210 benefits to utility-owned geothermal facilities. Utility companies and affiliated associations, on the other hand, generally favored the proposed rule.

The Commission believes it has the statutory authority under ESA to grant a UGSPPF all the exemptions under section 210(e) that a qualifying facility may obtain. Due to the overwhelming response of the State regulatory authorities, however, the Commission is withholding the exemptions from the FPA and State law at this time so it may further consider the implications of granting such exemptions. The Commission does not yet reach the issue of rate benefits pursuant to section 210(a).

Avoided Cost

Commenters noted that in some areas of the country the full "avoided cost" rate benefits are not needed to encourage geothermal small power production. The commenters suggest that, if the appropriate State regulatory authority determines that a rate less than avoided cost is sufficient to encourage rapid commercial development of geothermal small power production, the State regulatory authority should have the ability to set a lower rate for purchase.

The Commission has considered this suggestion during its original rulemaking proceeding on cogeneration and small power production.[6] Some comments received during the original rulemaking recommended that, as a matter of policy, a State regulatory authority or non-regulated utility be given the discretion to establish the relationship between avoided cost and rate for purchases.

The Commission in § 292.304 of its rules decided to set the rate for purchases at full avoided cost. The Commission continues to believe that such a rate for purchase is necessary to encourage cogeneration and small power production as required by section 210 of PURPA. A State regulatory authority is not precluded, however, from petitioning the Commission for a waiver of § 292.304 pursuant to § 292.403 of the Commission's rules.

§ 292.602 Exemption of qualifying facilities from the Public Utility Holding Company Act and certain State law and regulation.

This section is amended in paragraph (b) by adding a "utility geothermal small power production facility" to the types of facilities which shall not be considered to be an electric utility company as defined in section 2(a)(3) of the PUCHC, 15 U.S.C. 79(b)(a)(3). Furthermore, the Commission is extending the exemption from the PUHCA for qualifying small power production facilities using geothermal energy from 30 to 80 megawatts.

The applicability of § 292.602 includes those facilities described in § 292.601(a) of the Commission's rules. Therefore, the exemption of qualifying small power production facilities of 80 megawatts or less using geothermal energy as a primary energy source is accomplished by the change to § 292.601(a) described above.

The Commission notes that the Securities and Exchange Commission (SEC) has issued a final rule, entitled "Rules Exempting Certain Acquisition by Electric Utility Companies and Exempting Such Companies as 'Holding Companies'."[7] The SEC adopted Rule 14. which exempts from the requirements of sections 9(a)(2) and 10 of PUHCA the acquisition by one or more electric utility companies of the securities of a power supply company. The SEC also adopted Rule 15 which provides an exemption from regulation as a "holding company" under section 3(a)(2) of the PUHCA for an electric utility company that makes any such acquisitions.

The grant of exemption in Rule 14 by the SEC would, however, require: (1) authorization to acquire voting securities by "the regulatory authorities having jurisdiction over the rates and service" of the parent utility; (2) the subsidiary generating company to supply all of the electricity it generates to its parent company or companies (with certain noted exceptions); and (3) that the issuance of securities by the generating company be "expressly authorized by a regulatory authority having jurisdiction over its rates and service."[8]

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[6] 45 FR 12214, 12221 (Feb. 25, 1980).

[7] 46 FR 5867 (1981).

[8] *Id.* The exemptions are intended to facilitate joint ownership of conventional base-load

As indicated, the exemption under section 210(e) of PURPA eliminates the basis for the SEC's jurisdiction over acquisition and ownership of "qualifying" facilities or a UGSPPF. By excluding a UGSPPF from the definition of "electric utility company" under section 2(a)(3) of PUHCA, the Commission's rules eliminate the SEC's jurisdiction under section 9(a)(2) of PUHCA, thus rendering moot the exemption available under the SEC's Rules 14 and 15, as it pertains to geothermal facilities of 80 megawatts capacity or less.[9]

Environmental Conclusions

The Commission issued in June 1980, a draft environmental impact statement (DEIS) on rulemakings implementing sections 201 and 210 of PURPA. In the DEIS, the Commission determined that PURPA-induced development of geothermal small power production facilities would not create significant environment effects. In compliance with the National Environmental Policy Act of 1969 (NEPA), the Commission examined the environmental effects associated with these rules and has issued a Final Supplemental Environmental Impact Statement (EIS).[10]

The EIS accompanying this Order describes the environmental effects associated with the PURPA-induced development of small power production facilities using geothermal energy as a primary energy source. PURPA-induced development is anticipated in the near term for California, Nevada, and Idaho and may occur in other states in the West.

The revised rules under PURPA are expected to stimulate the development of up to 1,200 megawatts of electrical capacity from geothermal facilities by 1995. This is 1,100 megawatts more than predicted in the DEIS which the Commission prepared for the original rulemakings implementing sections 201 and 210 of PURPA.

The EIS found that geothermal resource development represents a relatively clean energy source and that increased geothermal development will reduce the adverse environmental impacts associated with nuclear and fossil fuel cycles.

III. Effective Date

These rules are effective May 1, 1981.

(Energy Security Act, Pub. L. No. 96-294, 94 Stat. 611 (1980) Public Utility Regulatoy Policies Act of 1978, 16 U.S.C. 2601, *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. 791 *et seq.*, Federal Power Act, as amended, 16 U.S.C. 792 *et seq.*, Department of Energy Organization Act, 42 U.S.C 7101 *et seq.*, 12009, 42 FR 46267)

In consideration of the foregoing, the Commission amends Chapter I of Title 18, Code of Federal Regulations, as set forth below.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,242]

46 F. R. 19465 (March 31, 1981)

18 CFR Parts 1 and 282

[Docket No. RM80-78; Order No. 134]

Delegation of Authority Under Natural Gas Policy Act of 1978 to Director, Office of Pipeline and Producer Regulation, To Grant Exemptions from Incremental Pricing

Issued: March 23, 1981.

AGENCY: Federal Energy Regulatory Commission.

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generation plants, but also have application to non-conventional base-load generation plants.

[9] This approach is similar to the exemption from PUHCA contained in section 9 of the Pacific Northwest Electric Power Planning and Conservation Act (S. 885), which would exempt a "generating company" from the definition of an electric utility company in PUHCA. The SEC has indicated its support, in principle, for that exemption.

[10] Western Regional, Final Supplemental Environmental Impact Statement, Small Power Production and Cogeneration Facilities—Eligibility, Rates and Exemptions for Qualifying and Utility-Owned Geothermal Small Power Production Facilities, Docket No. RM81-2, February 1981.

ACTION: Final rule.

SUMMARY: The Commission is adopting, as a final rule, an interim rule, issued on September 23, 1980, (45 FR 65170, October 1, 1980). This rule delegates the authority of the Commission under section 206(d) of the Natural Gas Policy Act to the Director of its Office of its Office of Pipeline and Producer Regulation to exempt on a case-by-case basis industrial fuel uses of natural gas otherwise subject to incremental pricing under section 201 of the Natural Gas Policy Act. This rule will reduce the number of applications for exemptions on which the Commission must act directly and thereby help expedite the application process.

EFFECTIVE DATE: This rule is effective April 22, 1981.

FOR FURTHER INFORMATION CONTACT:

Ronald Leach, Office of the General Counsel, 825 N. Capitol Street, NE., Washington, D.C. 20426, (202) 357–5417

Peter Lefkin, Office of the General Counsel, 825 N. Capitol Street, NE., Washington, D.C. 20426, (202) 357–8607

SUPPLEMENTARY INFORMATION: In the matter of delegation of authority under section 206(d) of the Natural Gas Policy Act of 1978 to the Director, Office of Pipeline and Producer Regulation, to grant exemptions from incremental pricing.

I. Introduction

The Federal Energy Regulatory Commission (Commission) is adopting, as a final rule, an interim rule promulgated pursuant to its authority under section 501(a) of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3301–3432). The interim rule, issued on September 23, 1980, (45 FR 65170, October 1, 1980) delegated the authority of the Commission under section 206(d) of the NGPA to the Director, Office of Pipeline and Producer Regulation, (Director) to exempt on a case-by-case basis industrial facility uses of natural gas otherwise subject to incremental pricing under section 201 of the NGPA.

Section 282.206 of the Commission's regulations was revised to implement this delegation on an interim basis and to prescribe for such exemptions the same standards and procedures employed by the Director in processing requests for Staff Adjustments under section 502(c) of the NGPA and § 1.41 of the Commission's regulations.

The Commission, in accordance with 5 U.S.C. 553(b), found good cause to waive the normal notice and comment procedures and the interim rule took effect immediately on September 23, 1980. The interim rule invited interested persons to file written comments and to request the opportunity to make an oral presentation of their views at a public hearing. Both Brooklyn Union Gas Company and United Distribution Companies (UDC) requested an oral hearing but later withdrew their requests. UDC filed the only written comment in this docket.

II. Discussion of UDC's Comment

UDC's comment supported the Commission's delegation order. It agreed with the Commission that the Director should handle petitions for exemptions of individual facilities on a case-by-case basis. It further agreed with the Commission that submission of individual exemption orders to Congress is not required under the language of section 206(d).

UDC also suggested that § 1.41(d)(2)(i) of the Commission's regulations, which sets forth certain procedures applicable to exemptive orders by the Director, be amended to require service of the petition for exemption on the Applicant's supplier. Section 1.41(d)(2)(i) currently reads as follows:

> (2) Service. (i) the applicant shall serve a copy of the application, or a copy from which confidential information has been deleted in accordance with paragraph (1) of the section on each person who is reasonably ascertainable by the applicant as a person who may suffer direct and measurable economic impact if the relief is granted.

UDC seeks to amend this provision by adding the following clause at the end thereof:

and on the applicant's immediate natural gas supplier.

UDC argues that the exemption of any individual facility pursuant to section 206(d) of the NGPA will directly affect the billings of the facility's gas suppliers. Consequently, UDC asserts that it is important that the supplier have prompt notice of the petition for exemption.

The Commission accepts with modification UDC's requested amendment. Section 1.41(d)(2)(i) is accordingly being amended to require service of notice to the natural gas supplier(s) of any applicant seeking an exemptive order pursuant to section 206(d). This provision is expressly limited to requests for exemptive orders pursuant to 206(d) and does not apply to any other petition filed under that section.

This provision is promulgated here on an interim basis because § 1.41 is an interim rule. At a later date, the Commission may make § 1.41 final under Docket No. RM79-32 (adjustment procedures).

Inasmuch as no other comments were filed, the Commission finds that the interim rule should be adopted as a final rule, amended as discussed above.

III. Effective Date

Since the amendment concerns a matter of agency practice and procedure, notice and public procedure thereon is unnecessary pursuant to 5 U.S.C. 553(b).

The final rule set forth below is effective on April 22, 1981.

(Natural Gas Policy Act of 1978, Pub. L. No. 95-621, 92 Stat. 3350 15 U.S.C. *et seq.* 3301-3432)

In consideration of the foregoing, the Commission amends Part 282, Subchapter I and, on an interim basis, § 1.41(d)(2)(i) Part I, Subchapter A, Chapter I, Title 18 of the Code of Federal Regulations as set forth below, effective April 22, 1981.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,243]

46 F. R. 20669 (April 7, 1981).

18 CFR Part 271

[Docket No. RM 79-76 (New Mexico-2)]

High-Cost Gas Produced From Tight Formations; Final Rule

Issued: March 30, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the New Mexico Oil Conservation Commission that the Atoka Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: March 30, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8559.

Order No. 138

The Commission hereby amends § 271.703(d) of its regulations to include the Atoka Formation in New Mexico as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued January 26, 1981 (46 FR 9962, January 30, 1981) based on a recommendation by the New Mexico Oil Conservation Commission (New Mexico), in accordance with § 271.703(c), that the Atoka Formation be designated as a tight formation.

Evidence submitted by New Mexico supports its assertion that the Atoka Formation meets the guidelines contained in § 271.703(c)(2).[1] The Commission adopts the New Mexico recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432; Administrative Procedure Act, 5 U.S.C. 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective March 30, 1981.

By the Commission.

Lois D. Cashell,
Acting Secretary.

[¶ 30,244]

46 F. R. 20669 (April 7, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Colorado-3)]

High-Cost Gas Produced From Tight Formations; Final Rule

Issued: March 30, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final Rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Colorado Oil and Gas Conservation Commission that the Niobrara Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: March 30, 1981.

FOR FURTHER INFORMATION CONTACT:

Leslie Lamer, (202) 357-8307, or Victor Zabel, (202) 357-8559.

Order No. 137

The Commission hereby amends § 271.703(d) of its regulations to include the Niobrara Formation in Colorado as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued September 23, 1980 (45 FR 65606, October 3, 1980)[1] based on a recommendation by the Colorado Oil and Gas Conservation Commission (Colorado) in accordance with § 271.703(c) that the Niobrara Formation should be designated as a tight formation.

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[1] Comments on the proposed rule were invited and received. No party requested a public hearing in this matter and no hearing was held.

Evidence submitted by Colorado supports its assertion that the Niobrara Formation meets the guidelines contained in § 271.703(c)(2). The Commission generally adopts the Colorado recommendation, with the modification discussed below.

Section 271.703(c)(2)(i)(D) of the Commission's regulations provides that in making recommendations for designations of tight formation areas to the Commission, a jurisdictional agency shall not include any formation or portion thereof

> [i]f the formation or any portion thereof was authorized to be developed by infill drilling prior to the date of recommendation and the jurisdictional agency has information which in its judgment indicates that such formation or portion subject to infill drilling can be developed absent the incentive price established in paragraph (a) of this section. . . .

In reviewing Colorado's recommendation, the Commission found evidence indicating that ten fields within the recommended formation had been authorized to be developed by infill drilling prior to the date the recommendation was made.[2] Three of the ten fields had been substantially developed before the infill drilling orders for those fields were issued. They are the Beecher Island Field (Order No. 300–5), the Mildred Field (Order No. 327–3), and Waverly Field (Order No. 328–3). The Beecher Island Field was comprised of forty 640-acre units and wells had been drilled in 28 of the units at the time of issuance of the infill drilling order; the Mildred and Waverly Fields were 100% developed on the 640-acre units at the time their infill drilling orders were issued.[3] Accordingly, the Commission is excluding the 45 sections which make up the entire Mildred and Waverly Fields, and the 28 units in the Beecher Island Field, on which wells were drilled at the time of issuance of the infill drilling orders, from the designation of the Niobrara Formation as a tight formation.[4] The exclusion of these three fields at this time does not preclude them from future designation if economic data should demonstrate that all or part of the excluded area cannot be further developed absent the incentive price.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately established good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432; Administrative Procedure Act, 5 U.S.C. 533)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, Code of

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[1] Comments were invited and none were received. No party requested a public hearing in this matter and no hearing was held.

[2] Colorado reduced well spacing from 640 acres to 160 acres on August 22, 1978.

[3] The applicable infill drilling orders, cited above, contain a finding made by Colorado that the data available indicates that "one well will efficiently and *economically* drain an area of not more than 160 acres * * *" [emphasis added]. This economic finding in addition to substantial development also indicates that the incentive price set under section 107(c)(5) is not necessary to encourage drilling in these fields, as the wells were found to be economical at prices already available.

[4] The excluded sections are found in Yuma County, Colorado, as follows: T3N, R46W, Sec. 6; T4N, R46W, Sec. 8, 16, 17, 20, 21, 29–32; T2S, R46W, Sec. 12–16, 23, 24; T2S, R44W, Sec. 12, 13, 24; T2S, R43W, Sec. 3–6, 7–10, 15–22, 27–34; T3S, R43W, Sec. 5, 6.

Federal Regulations, is amended as set forth below, effective March 30, 1981.

By the Commission.

Lois D. Cashell,
Acting Secretary.

[¶ 30,245]

46 F. R. 20670 (April 7, 1981).

18 CFR Part 271

[Docket No. RM79-76 (Ohio—1)]

High-Cost Gas Produced From Tight Formations; Final Rule

Issued: March 30, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Ohio Division of Oil and Gas, Department of Natural Resources, as modified, that the Clinton Sandstone Formation, be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: March 30, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or John Roy Johnson, (202) 357-8732.

Order No. 136

The Commission hereby amends § 271.703(d) of its regulations to include the Clinton Sandstone Formation in Ohio as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued December 22, 1980 (46 FR 941, January 5, 1981) based on a recommendation by the Ohio Division of Oil and Gas, Department of Natural Resources (Ohio) in accordance with § 271.703(c), that the Clinton Sandstone Formation be designated as a tight formation.

Evidence submitted by Ohio and the commenters supports Ohio's assertion that the Clinton Sandstone Formation meets the guidelines contained in § 271.703(c)(2).[1] One commenter, Columbia Gas Transmission Corporation (Columbia), noted in its comment that although Ohio indicated in a public hearing that it would exclude all gas storage field areas from its recommendation, certain portions of the recommended area were located in Columbia's designated gas storage fields. These areas should be excluded, according to Columbia, because they fail to meet the guidelines for tight formations found in § 271.703(c)(2)(i), and further, because designation as a tight formation should cause problems for storage field operators in protecting the reservoir integrity of storage fields. Ohio agreed with Columbia's comment and, on February 9, 1981, amended its recommendation accordingly. The amendment removed from the recommendation portions of Lot 7, Chatham Township, Lots 46 and 47, Litchfield Township, Lots 20 and 21, York Township, in Medina County, and Section 21 Plain Township, in Wayne County. The amendment further stipulated that "any well drilled in the designated tight formation, that is completed within a gas storage reservoir or 'reservoir protective area,' as defined by maps on file with Ohio on February 1, 1981, shall be excluded from the tight formation designation." The Commission adopts the Ohio recommendation, as modified by Ohio on February 9, 1981, to exclude the above-named areas in Medina and Wayne Counties, and to exclude designated gas storage reservoirs and reservoir protective areas from the designated tight formation.

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[1] Comments on the proposed rule were invited and received. No party requested a public hearing in this matter, and no hearing was held.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432; Administrative Procedure Act, 5 U.S.C. 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective March 30, 1981.

By the Commission.

Lois D. Cashell,
Acting Secretary.

[¶ 30,246]

46 F. R. 20980 (April 8, 1981).

18 CFR Part 274

[Docket No. RM79-3; Order No. 130]

Natural Gas Policy Act of 1978; Railroad Commission of Texas' Application for Alternative Filing Requirements; Final Rule

Issued: April 1, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: This order adopts a proposal submitted to the Commission by the Railroad Commission of Texas to institute alternative filing requirements for applications for well eligibility determinations made under section 102 of the Natural Gas Policy Act of 1978 with the Railroad Commission of Texas. Alternative filing requirements are provided for in § 274.207(f) of the Commission rules which implement the NGPA. A new § 274.208(d) is added to contain the alternative requirements as approved by the Federal Energy Regulatory Commission.

EFFECTIVE DATE: April 1, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8307, or William Bushey, (202) 357–8590.

SUPPLEMENTARY INFORMATION:

In the matter of Natural Gas Policy Act of 1978, Railroad Commission of Texas' application for alternative filing requirements; order issuing alternative filing requirements; order issuing alternative filing requirements.

I. Background

On December 22, 1980, the Railroad Commission of Texas (Texas) filed an application with the Federal Energy Regulatory Commission (Commission) for approval of alternative filing requirements pursuant to § 274.207 of the Commission's regulations.[1] The proposed alternative filing requirements concern filings made under section 102 of the Natural Gas Policy Act of 1978 (NGPA). Two changes are proposed: one involves new onshore wells and the other involves new onshore reservoirs. Notice of the Texas application was issued on January 19, 1981,[2] and the comment period expired on February 3, 1981. Two comments were received, from Exxon Corporation and Texas Independent Producers and Royalty Owners Association, both in support of Texas' application.[3] No party requested a hearing, and no hearing was held.

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[1] A supplement to the application, which clarified the proposed changes, was received by the Commission from Texas on January 5, 1981.

[2] 46 FR 8670, January 27, 1981.

[3] Two additional comments were received after the comment period expired. These comments, filed by Arco Oil and Gas Company and Mueller Engineering Corporation, also supported Texas' application.

II. Discussion

Section 102(c)(1)(B)(ii) of the NGPA qualifies a well as a new onshore well if the completion location of that well is located at least 1,000 feet below the deepest completion location of each marker well within 2.5 miles of the new well. Section 274.202(c)(2)(iv) of the Commission's regulations requires that the deepest completion location of all marker wells within 2.5 miles of the subject well be listed. In Texas' proposed rule [4] only the deepest completion location of the deepest completed marker well within 2.5 miles is required to be listed. Texas asserts that this single listing is sufficient to satisfy the "1,000 feet deeper" test of section 102(c)(1)(B)(ii) of the NGPA.

The Commission agrees with Texas that the identification of the deepest completion location of the deepest completed marker well within 2.5 miles of the subject well, supported by the oath statements required under §§ 274.202(c)(2)(vi) and 274.202(e) (which Texas does not propose to change), provides substantial evidence to determine that the subject well has met the "1,000 feet deeper" test for a new onshore well under section 102(c)(1)(B)(ii) of the NGPA.

Texas' second proposed change in the filing requirements concerns the new onshore reservoir determination under section 102 of the NGPA. Section 274.202(d)(1)(ii) of the Commission's regulations requires that an applicant file geological information sufficient to prove that the subject well is completed in a reservoir which qualifies as a "new onshore reservoir." This information is to include, to the extent reasonably available, well logs, bottom hole or pressure surveys, well potential tests, formation structure maps, subsurface cross-section charts and gas analyses. Texas' proposed rule [5] would require, in lieu of this information, a copy of Railroad Commission Form P-7 and the order or notice issued by the Railroad Commission designating a new reservoir and/or new field status for the reservoir in which the subject well is completed. Texas requires that for a reservoir to be designated by the state as a new reservoir and/or a new field, the operator must file Texas Form P-7 for consideration by the Railroad Commission. Texas Statewide Rule 41 (051.02.02.041), Application For New Oil or Gas Field Designation And/Or Allowable, requires that the following be included with the application (Form P-7):

(1) An area map showing all wells, active and abandoned, within a 2.5 mile radius of the subject well; the depths and producing intervals of those wells; all nearby fields, past or present; and the producing formations.

(2) Full scale electrical logs of the well with the subject formation and all nearby producing formations identified clearly.

(3) Subsurface structure map, geological cross section from electrical logs, reservoir pressure measurements, or core data and drill-stem test data—whichever of the above is necessary to indicate separation from other producing formations.

Texas points out that the well and reservoir data supplied in support of the Form P-7 is examined by a legal and technical staff to assure the conservation of natural resources, prior to the granting of new reservoir/new field status. Texas asserts that this review need not be duplicated by its NGPA section. Texas maintains that all information used in state conservation findings, which also supports the NGPA application, remains available in Texas' central records. Texas further states that although there are procedural differences, the basis for determinations under the proposed rules remains identical to that basis required under the present regulations, and will provide substantial evidence on which Texas may base a determination that a reservoir is a new onshore reservoir. Finally, under the Texas proposal, the applicant would still be required to submit a plat showing the subject well and all wells which penetrated the subject reservoir, and would be required to prove that the exclusions listed in Section 102(c)(1)(C) of the NGPA do not apply.

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[4] Rules of the Railroad Commission of Texas, Oil and Gas Division, NGPA State Alternative Procedures, Rule 051.02.04.003(b)(1).

[5] Rules of the Railroad Commission of Texas, Oil and Gas Division, NGPA State Alternative Procedures, Rule 051.02.04.003(b)(2).

In view of the requirements of Texas Statewide Rule 41 and the analysis given the data filed under that rule, prior to the designation of a new reservoir for state conservation purposes, the Commission considers that the filing of identical data for a new onshore reservoir determination under section 102 of the NGPA to be an unnecessary duplication of filing requirements. The Commission finds that the inclusion of Texas Form P-7 and a copy of the notice or order from the Railroad Commission granting new reservoir and/or new field status, in lieu of the geological data required in § 274.202(d)(1)(ii), would be sufficient to insure that the geological requirements for a new onshore reservoir have been met. The documents required by the proposed rule, coupled with the appropriate oath statements and the applicant's proof that the exclusions listed in section 102(c)(1)(C) of the NGPA do not apply, would provide substantial evidence upon which Texas could make a determination.

III. Public Procedures and Effective Date

Notice of Texas' proposal was issued on January 19, 1981. No party requested a hearing and no hearing was held. Comments on the proposal were due February 3, 1981. Two comments were timely received in support of Texas' proposal. In view of the comments and the preceding discussion, the Commission approves Texas' alternative filing requirements, described above.

The Commission believes that since the alternative filing requirements remove significant administrative burdens from applicants seeking well determinations from Texas under section 102 of the NGPA, good cause exists to make the alternative filing requirements effective immediately for all determinations which have not yet become final under § 275.202 as of the day before the date of issuance of this order.

(Natural Gas Act, 15 U.S.C. 717 *et seq.*; Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3432)

In consideration of the foregoing, Part 274 of Subchapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective April 1, 1981.

By the Commission.

Lois D. Cashell,
Acting Secretary.

[¶ 30,247]

46 F. R. 15874 (March 10, 1981).

18 CFR Part 250

[Docket No. RM76-15]

Regulation of Small Producers Order Denying Rehearing

Issued: March 3, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Order denying rehearing and amending regulation.

SUMMARY: On August 10, 1977, and August 15, 1977, applications for rehearing and/or clarification of Order No. 568, *Order Amending and Clarifying Small Producer Regulations*, issued July 14, 1977, were filed. Order No. 568 amended regulations exempting small producers from certain filing requirements in 18 CFR 157.40. On September 7, 1977, the Commission granted rehearing for purposes of further consideration. This order denies the

petitions for rehearing, and amends § 250.10 by inserting a copy of the application form small producers are required to file.

EFFECTIVE DATE: March 3, 1981.

FOR FURTHER INFORMATION CONTACT: Richard E. Kelly, (202) 357-8315.

SUPPLEMENTARY INFORMATION: On August 10, 1977, and August 15, 1977, respectively, applications for rehearing and/or clarification of Order No. 568, *Order Amending and Clarifying Small Producer Regulations,* issued July 14, 1977, were filed by Texas Oil & Gas Corp., *et al.* (TXO) and American Liberty Company (American Liberty). Order No. 568 amended regulations exempting small producers from certain filing requirements in § 157.40. On September 7, 1977, the Commission [1] granted rehearing for purposes of further consideration.

I

Section 157.40(a)(1) provides that a small producer applicant's total annual jurisdictional sales volumes include the jurisdictional sales volumes of a pipeline company with which the applicant is affiliated. In its application for rehearing TXO contests this provision.

TXO states that the regulations provide that a producer need only include its own sales and sales by "affiliated producers" in computing its total annual jurisdictional sales volumes. It follows, TXO claims, that sales made by a pipeline company should not be included since a pipeline, by definition, is not a producer.

TXO further asserts that the same volumes may be counted twice where the small producer applicant makes sales to its affiliated pipeline since the gas will be counted once in the producer's sale and a second time in the pipeline's resale. TXO also states that if the jurisdictional sales of an affiliated pipeline company are to be considered, it is unclear whether the direct sales volumes of the pipeline are to be included.

We will deny rehearing. Prior to Order No. 568 the small producer regulations did not permit a producer to qualify as a small producer if it was affiliated with a natural gas pipeline company. The rationale for this policy was set forth in Order No. 308 [2] wherein the Commission first adopted the small producer regulations. There the Commission stated:

> El Paso has suggested that pipeline companies be excluded from the definition of "affiliated producers" under the common control test. We do not adopt this suggestion and make clear, to the contrary, that a company which is affiliated with a pipeline company is not eligible for the "small producer" classification, even though its jurisdictional sales be small. The rationale underlying the special relief afforded small producers applies only to fully-independent entities and not to companies which have the advantage of a pipeline affiliation.

In Order No. 568 the Commission relaxed this blanket pipeline affiliation prohibition and provided that a producer which was affiliated with a pipeline company other than a Class A pipeline could qualify for small producer status. The Commission also provided, however, that such a producer, in computing its total jurisdictional sales volume, would have to include the jurisdictional sales of its pipeline affiliate [3] as its own in the same fashion producer is required to include not only its own jurisdictional sales, but also the jurisdictional sales of the producer with which it is affiliated.[4] In this way the Commission sought to ascertain more accurately whether, in terms of jurisdictional sales, a small producer applicant was in fact "small." In our view, the approach adopted in Order

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[1] The term "Commission," when used in the context of action taken prior to October 1, 1977, refers to the Federal Power Commission; when used otherwise, the reference is to the Federal Energy Regulatory Commission.

[2] 34 FPC 1202, 1203 (1965).

[3] As to a non-jurisdictional pipeline, the jurisdictional volumes would be those sold under the emergency provisions of the Commission's regulations.

[4] Direct sales volumes of a pipeline are not to be included since direct sales are not jurisdictional.

No. 568 is reasonable and we will adhere to it.[5]

TXO also seeks rehearing of the Commission's decision to limit a small producer to the applicable large producer rate ceiling for sales from reserves developed by it while in large producer status. TXO states that the result of the new restriction is to limit severely the volumes which the small producer can sell at small producer rates. TXO also asserts that many producers which now qualify as small producers were regulated as large producers prior to the issuance of Order No. 428[6] and are not now precluded from receiving small producer rate treatment for sales from reserves developed while they were so regulated.

One of the reasons that the Commission instituted the instant rulemaking proceeding was to amend the small producer regulations insofar as they apply to a situation such as that described by TXO.[7] In *Suburban Propane Gas Corporation,* Docket No. CS75-396, issued May 27, 1976, the Commission permitted sales from reserves developed by a large producer which then became a small producer to receive small producer rate treatment. The Commission there recognized, however, that while this interpretation of the regulations was dictated by the plain language of the regulations, such interpretation was not consistent with the purpose of the small producer program.[8] It was the Commission's view then, and it is our view now, that where the costs and risks associated with the development of gas reserves are borne by a large producer, those reserves should not be accorded small producer rate treatment.[9]

TXO's claim of discrimination against those former large producers which attain small producer status subsequent to July 13, 1977, is not persuasive. The Commission in Order No. 568 concluded that large producers which become small producers on or after July 14, 1977, should not be permitted small producer treatment for those reserves developed by them while they were large producers, thus eliminating for future small producers the ruling in *Suburban Propane.* The Commission has not imposed this rule on those who acquired small producer status prior to the issuance of Order No. 568, and it is not required to do so in order to apply the rule prospectively to those who become small producers after issuance of Order No. 568.[10]

II

American Liberty in its petition requests that the Commission confirm that sales from processing plants and gathering facilities made by small producers qualify as small producer sales. It asserts that any change in the regulations brought about by Order No. 568 which excludes such sales from small producer treatment was not discussed or justified by the Commission in its notice of rulemaking and thus does not comply with the Administrative Procedure Act.[11] American Liberty further asserts that any such change was required to be explained by the Commission.

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[5] Where the possibility of a double counting of volumes arises, the small producer applicant may request a waiver of the regulations.

[6] 45 FPC 454 (1971).

[7] Notice of Proposed Rulemaking, issued May 25, 1976, at 2.

[8] Section 157.40(c) of the Commission's regulations in effect at that time provided that small producers were limited to large producer rates for jurisdictional sales where the gas reserves relating thereto were acquired by the purchase of developed reserves in place from a large producer. Since Suburban had not purchased reserves from a large producer, the Commission permitted it to collect small producer rates for the reserves developed by it while in large producer status.

[9] In addition, acceptance of TXO's argument would encourage large producers whose annual sales are just above the 10,000,000 Mcf level to limit production or sell some producing properties so as to reduce sales to just under that level and thereby receive small producer rates for all of their sales. We do not believe this result to be in the public interest.

[10] We also note that most current small producers were "small" during the time prior to Order No. 428 when they were being regulated as large producers. In this context, therefore, it was reasonable for the Commission in Order No. 428 to permit small producers to receive small producer treatment for sales from reserves developed while they were regulated as large producers.

Order No. 568 effected no modifications in the small producer regulations with respect to sales made by small producers from processing plants or gathering facilities. Under the regulations a small producer plant operator or gatherer who purchases gas from a small producer is entitled to collect small producer rates for its resales of the gas. Where the small producer plant operator or gatherer purchases gas from a large producer, however, it is limited to large producer rates for its resales.[12]

III

Order No. 568 left the proceedings in this docket open as to proposed revisions of Form Nos. 314–A, Application for Small Producer Certificate, and 314–B, Annual Statement for Independent Producer Holding Small Producer Certificate. Passage of the Natural Gas Policy Act of 1978 has reduced substantially the number of small producer certificate applications. Accordingly, we believe that the proposed revisions of the small producer certificate application form are no longer necessary. We will, however, incorporate Form 314–A into the Commission's regulations (§ 250.10) in the same manner as other prescribed producer application forms.

Elimination of Form 314–B is being proposed in another docket. All matters relating to the revision of Form 314–B will be considered in that docket.

The Commission orders:

(A) TXO's application for rehearing is denied.

(B) American Liberty's application for rehearing and/or clarification is granted only to the extent provided hereinabove. In all other respects the application is denied.

(C) Section 250.10 of Part 250, Subchapter C of Chapter I, Title 18 of the Code of Federal Regulations, is amended to incorporate Attachment A hereto. Because the amendment does not change any substantive rule, and only places in the regulations a copy of the application form small producers have been required to file, good cause exists to make it effective immediately.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,248]

46 F. R. 22180 (April 16, 1981);
46 F. R. 23048 (April 23, 1981);
46 F. R. 25064 (May 5, 1981)

18 CFR Parts 46 and 131

[Docket No. RM 81–28; Order No. 140]

Public Utility Filing Requirement; Order Establishing Format No. FERC 561, Annual Report of Interlocking Positions

Issued: April 9, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) hereby amends the Commission's regulations to provide a standard format, identified as Format No. FERC 561, for the reporting of information respecting interlocking positions held by a person in both a public utility and in certain other specified entities.

This rule makes no substantive changes in the current interlocking directorate reporting requirements; instead, it merely provides a format for these reports.

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[11] 5 U.S.C. 551, *et seq.*

[12] *See Nelah Gas & Oil Corporation, et al.*, Docket No. CS75–363, issued April 12, 1977.

Information which is uniformly submitted on Format No. FERC 561 will be utilized more efficiently by the Commission for its regulatory purposes. The use of the format will also ease respondent reporting burdens—it will be preprinted for submissions after the initial filing, and only amendments to previously reported items which have since changed—or new data items—will have to be indicated on this preprinted format.

Immediate promulgation of this rule will allow the persons required to file this data to use the new format before the April 30, 1981 filing deadline occurs. Nevertheless, persons who have already submitted their reports in accordance with the former rule, will not be required to "refile" a report in accordance with this new format.

EFFECTIVE DATE: April 9, 1981.

FOR FURTHER INFORMATION CONTACT: Charles Harland, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Room 403RB, Washington DC 20426, (202) 376-1653

SUPPLEMENTARY INFORMATION:

I. Background and Summary

By this rule, the Federal Energy Regulatory Commission (Commission) implements a specific format for use in reporting information respecting interlocking positions which is required pursuant section 305(c) of the Federal Power Act (16 U.S.C. 792–828c).

Part 46 of the Commission's regulations implements section 305(c) of the Federal Power Act as amended by section 211 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2601–2645).

Section 305(c)(2) provides that by January 31 of each calendar year, public utilities shall file, pursuant to Commission regulations, a list of their twenty largest purchasers of electric energy. A final rule to implement this provision was issued on January 11, 1980 (Order No. 67, 45 FR 3569, January 18, 1980; amended to correct technical errors on January 21 and February 4, 1980, 45 FR 6377, January 28, 1980; 45 FR 9729, February 13, 1980). That rule established §§ 46.1 through 46.3 of the Commission's regulations.

Section 305(c)(1) of the Federal Power Act authorizes the Commission to prescribe the "form and manner" of a written statement to be filed on or before April 30 of each year by any person holding interlocking positions in both a public utility and in any of certain other specified entities. Regulations to implement this provision were issued on April 2, 1980 (45 FR 23413, April 7, 1980), which established §§ 46.4 through 46.6.

Pursuant to the instant rulemaking, the contents of the written statement of a person holding such interlocking positions (prescribed in § 46.6) are now incorporated in a standardized format, designated as Format No. FERC 561. Format No. FERC 561 is set out at new § 131.31 of the Commission's regulations.

The reporting requirement itself is not altered by this rulemaking—only the form in which it is submitted.

The Commission has promulgated this format for written statements prescribed in § 46.6 because those persons who submitted the statement in 1980 (the first year the filing of this data was required) did not submit the requisite information in a uniform fashion. The Commission staff found it difficult, in some cases, to coordinate the data for use in its regulatory analyses. Therefore, the Commission has standardized the form of this report to facilitate entry into a computer system and to correspondingly reduce the time and effort necessary to review the reported information.

Not only will the establishment of Format No. FERC 561 and computerization of the reported data improve the Commission's use of this information, it will also reduce the reporting burden of the persons who respond to the requirement. The reports, once submitted to the Commission, will be preprinted and sent to respondents in subsequent year. Respondents will simply have to verify that the data is correct, or in the event of changes, alter only those data elements which have been added to or changed.

II. Effective Date

The promulgation of Format No. FERC 561 amends the Commission's regulations to provide a standard format for the reporting of information which is currently prescribed in section 305(c) of the Federal Power Act. This rulemaking does not otherwise alter the existing requirement to report information pursuant to §46.4 of the Commission's regulations. In order that as many persons as possible who file a statement pursuant to §46.4 may benefit from use of the new Format No. FERC 561 before the April 30, 1981 deadline for 1980 reports, the Commission makes this rulemaking effective as of April 9, 1981.

The Commission finds that notice and public procedure are unnecessary pursuant to 5 U.S.C. 553(b), and that there is good cause under 5 U.S.C. 553(d) to make the amendments in this rulemaking effective immediately.

(Department of Energy Organization Act, 42 U.S.C. 7101–7352; Federal Power Act, 16 U.S.C. 792–828c; Public Utility Regulatory Policies Act, 16 U.S.C. 2601–2645; E.O. 12009, 3 CFR 142 (1978))

In consideration of the foregoing, Title 18 of the Code of Federal Regulations is amended in Parts 46 and 131 as set forth below, effective April 9, 1981.

By the Commission.

Lois D. Cashell,
Acting Secretary.

[¶ 30,249]

46 F. R. 24174 (April 30, 1981)

18 CFR Part 271

[Docket No. RM80-53]

Maximum Lawful Prices Under the Natural Gas Policy Act for May, June, and July 1981

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: Pursuant to the authority delegated by 18 CFR 357.307(1), the Director of the Office of Pipeline and Producer Regulation revises and publishes the maximum lawful prices prescribed under Title I of the Natural Gas Policy Act (NGPA) for the months of May, June, and July, 1981. Section 101(b)(6) of the NGPA required that the Commission compute and publish the maximum lawful prices before the beginning of each month for which the figures apply.

EFFECTIVE DATE: May 1, 1981.

FOR FURTHER INFORMATION CONTACT: Kenneth A. Williams, Director, OPPR (202) 357–8500.

Publication of Prescribed Maximum Lawful Prices Under the Natural Gas Policy Act of 1978.

Order Of The Director, OPPR

Issued April 22, 1981.

Section 101(b)(6) of the Natural Gas Policy Act of 1978 (NGPA) requires that the Commission compute and make available maximum lawful prices and inflation adjustments prescribed in Title I of the NGPA before the beginning of any month for which such figures apply.

Pursuant to this requirement and § 375.307(1) of the Commission's regulations, which delegates the publication of such prices and inflation adjustments to the Director of the Office of Pipeline and Producer Regulation, the maximum lawful prices for the months of May, June, and July, 1981, are issued by the publication of the price tables for the applicable quarter. Pricing tables are found in § 271.101(a) of the Commission's regulations. Table I of § 271.101(a) specifies the maximum lawful prices for gas subject to sections 102, 103, 106(b)(1)(B), 107(c)(5), 108, and 109 of the NGPA. Table II of § 271.101(a) specifies the maximum lawful prices for sections 104 and 106(a) of the NGPA.

Table III of § 271.102(c) contains the inflation adjustment factors.

Kenneth A. Williams,
Director, Office of Pipeline and Producer Regulation.

[¶ 30,250]

46 F. R. 24548 (May 1, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Colorado-11); Order No. 142]

High-Cost Gas Produced From Tight Formations; Colorado

Issued April 29, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Colorado Oil and Gas Conservation Commission that the Mancos "B" Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective April 29, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8559.

The Commission hereby amends § 271.703(d) of its regulations to include the Mancos "B" Formation in Rio Blanco and Garfield Counties, Colorado as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued February 4, 1981 (46 FR 11839, February 11, 1981)[1] based on a recommendation by the Colorado Oil and Gas Conservation Commission (Colorado) in accordance with § 271.703(c), that the Mancos "B" Formation be designated as a tight formation.

Evidence submitted by Colorado supports its assertion that the Mancos "B" Formation meets the guidelines contained in § 271.703(c)(2).[1] The Commission adopts the Colorado recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3432; Administrative Procedure Act, 5 U.S.C. 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective April 29, 1981.

By the Commission

Kenneth F. Plumb,
Secretary.

[¶ 30,251]

46 F. R. 24548 (May 1, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Colorado-13); Order No. 143]

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[1] Comments on the proposed rule were invited and received. No party requested a public hearing in this matter and no hearing was held.

High-Cost Gas Produced From Tight Formations; Colorado

Issued April 29, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Colorado Oil and Gas Conservation Commission that the Mancos "B" Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective April 29, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8559.

The Commission hereby amends § 271.703(d) of its regulations to include the Mancos "B" Formation in Rio Blanco County, Colorado, as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued February 4, 1981 (46 FR 11840, February 11, 1981) [1] based on a recommendation by the Colorado Oil and Gas Conservation Commission (Colorado) in accordance with § 271.703(c), that the Mancos "B" Formation be designated as a tight formation.

Evidence submitted by Colorado supports its assertion that the Manco "B" Formation meets the guidelines contained in § 271.703(c)(2).[1] The Commission adopts the Colorado recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3432; Administrative Procedure Act, 5 U.S.C. 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective April 29, 1981.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,252]

46 F. R. 24549 (May 1, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Louisiana-2); Order No. 141]

High-Cost Gas Produced From Tight Formations; Louisiana

Issued April 29, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by

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[1] Comments on the proposed rule were invited and received. No party requested a public hearing in this matter and no hearing was held.

section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR § 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the State of Louisiana Office of Conservation that the Haynesville Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective April 29, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8307, or Ting Chin, (202) 357–8595/John Bassett, (202) 357–8589.

The Commission hereby amends § 271.703(d) of its regulations to include the Haynesville Formation in Louisiana as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued January 21, 1980 (46 F.R. 8568, January 27, 1981) [1] based on a recommendation by the State of Louisiana Office of Conservation (Louisiana) in accordance with § 271.703(c), that the Haynesville Formation be designated as a tight formation.

Evidence submitted by Louisiana supports its assertion that the Haynesville Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Louisiana recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432; Administrative Procedure Act, 5 U.S.C. 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective April 29, 1981.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,253]

46 F. R. 24550 (May 1, 1981)

18 CFR Part 294

[Docket RM 79–52]

Interim Procedures for Shortages of Electric Energy and Capacity Under Section 206 of the Public Utility Regulatory Policies Act of 1978; Extension

Issued April 23, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Amendment to Extend Interim Regulation.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts regulations which extend, through April 30, 1982, its interim regulations implementing accommodation and reporting procedures for shortages of electric energy and capacity under section 206 of the Public Utility Regulatory Policies Act of 1978. This rulemaking extends the effectiveness of

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[1] Comments on the proposed rule were invited and none were received. No party requested a public hearing in this matter, and no hearing was held.

the interim regulations, and make no other changes. Under the extended regulations, each public utility now serving firm power wholesale customers must report any shortages of electric energy or capacity anticipated to occur prior to April 30, 1982, to the Commission, the utility's customers, and appropriate State authorities. Also, the regulations require each public utility to report any modifications of its plans for accommodating shortages which may occur before April 30, 1982.

EFFECTIVE DATE: April 23, 1981.

FOR FURTHER INFORMATION CONTACT:

Bernard B. Chew, Office of Electric Power Regulation, 825 North Capitol Street, NE., Room 504RB, Washington, D.C. 20426 (202) 376-9264

Christine P. Benagh, Office of the General Counsel, 825 North Capitol Street, NE., Room 8104-B, Washington, D.C. 20426 (202) 357-8606

SUPPLEMENTARY INFORMATION: Before Commissioners: Georgiana Sheldon, Acting Chairman; Matthew Holden, Jr., George R. Hall and J. David Hughes.

I. Background

On June 15, 1979, the Commission issued interim regulations implementing, in part, section 206 of the Public Utility Regulatory Policies Act of 1978 (PURPA).[1] Section 206 of PURPA directs the Commission to require public utilities to report anticipated shortages of electric energy or capacity to the Commission and to appropriate State authorities. Section 206 also requires public utilities to submit contingency plans to accommodate any shortages of electric energy or capacity to the Commission and to appropriate State authorities.

Paragraph (b) of the interim regulations requires each public utility serving firm power wholesale customers to submit by July 23, 1979, "a brief statement indicating how it would accommodate any shortages of electric energy or capacity affecting its firm power customers, should such a shortage occur prior to September 30, 1979."[2]

Paragraph (c) of the interim regulations requires each utility to report immediately any shortage of electric energy or capacity which the utility anticipates will occur. In that report the utility must provide the Commission with certain information, including information regarding any procedures for accommodating a particular shortage, if they differ from the procedures set out in the utility's statement submitted pursuant to paragraph (b) of the interim regulations.

Prior to this amendment, paragraph (a) defined "anticipated shortages of electric capacity or energy" as those situations which would result in shortages "anticipated to occur prior to April 30, 1981."[3] The purpose of this amendment is to extend the reporting requirements through April 30, 1982, so that the Commission will be advised of any anticipated shortages which may occur during the coming year while the Commission considers appropriate action in view of the responses received to the Notice of Inquiry issued in this docket on April 1, 1980.[4]

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[1] Interim Regulations, 18 CFR 294.101 (1979), Docket No. RM79-52 (issued June 15, 1979).

[2] This language was adopted by an Amendment to Interim Regulations, 18 CFR 294.101, Docket No. RM79-52 (issued August 1, 1979) in order to make clear the Commission's intent that all public utilities serving firm customers must submit statements concerning the methods by which they accommodate possible shortages. Before this amendment, the language appeared to suggest that only those utilities which anticipated shortages prior to September 30, 1979, were obliged to file accommodation reports under section 206(a) of PURPA.

[3] This date was initially September 30, 1979, but was extended to April 30, 1980, by Interim Regulations, 18 CFR 294.101, Docket No. RM79-52 (issued Oct. 23, 1979). It was extended to April 30, 1981, by Amendment to Extend Interim Regulations, 18 CFR 294.101, Docket No. RM79-52 (issued Apr. 1, 1980).

[4] Inquiry Implementing Section 206 of the Public Utility Regulatory Policies Act of 1978, Continuance of Service, Docket No. RM79-52, issued April 22, 1980, 45 Fed. Reg. 28,102 (April 28, 1980).

Accordingly, the Commission hereby amends the interim regulations. First, the reporting requirements of paragraph (c) are extended through April 30, 1982 by amending the definition of "anticipated shortages of electric energy or capacity" in paragraph (a) to include those situations anticipated to occur prior to April 30, 1982. Second, if a plan to accommodate a shortage occurring prior to April 30, 1982, differs from the plan submitted pursuant to paragraph (b) of the interim regulations, the utility is hereby required to file a supplemental statement setting forth those changes. A utility need not file a statement of its plan to accommodate shortages prior to April 30, 1982, if that plan does not vary from that set out in the statement already filed pursuant to paragraph (b).

II. Effective Date

Since the Commission is mandated by statute to have in effect rules regarding the continuance of electric service, good cause exists for the immediate effectiveness of this amendment. Therefore, the Commission finds it to be in the public interest to dispense with notice and comment under 5 U.S.C. 553(b) and to make this rule effective immediately.

(Public Utility Regulatory Policies Act of 1978, Pub. L. 95-617, 92 Stat. 3117 (1978); Federal Power Act, 16 U.S.C. 792-828c; Exec. Order No. 12,009, 3 CFR 142 (Comp. 1977); Administrative Procedure Act, 5 U.S.C. 553)

In consideration of the foregoing, Part 294 of Subchapter K, Chapter I, Title 18 of the Code of Federal Regulations is amended as set forth below, effective April 23, 1981.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,254]

46 F. R. 26613 (May 14, 1981)

18 CFR Part 2

[Docket Nos. RM80-42, R-424 and R-446]

Regulations Implementing Tax Normalization for Certain Items Reflecting Timing Differences in the Recognition of Expenses or Revenues for Ratemaking and Income Tax Purposes

Issued: May 6, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule Requiring Tax Normalization and Order Removing Refund Contingencies.

SUMMARY: The Commission amends Part 2 of its regulations to require a public utility making a rate filing under the Federal Power Act or an interstate pipeline making a rate filing under the Natural Gas Act to use tax normalization for miscellaneous timing differences to compute the income tax component of its cost of service. The rule requires a rate applicant to use tax normalization for all timing difference transactions except those addressed in prior Commission orders. The rule also codifies the existing Commission practice of adjusting rate base for accumulated deferred income taxes. Finally, the rule requires a rate applicant to make provision in the income tax component of its cost of service for any excess or deficiency in the deferred tax accounts due to tax rate changes and to timing difference transactions within the scope of the rulemaking that had previously been given flow-through treatment.

In addition to this final rule, the Commission orders that refund contingencies imposed in certain cases prior to the issuance of the final rule and relating to tax normalization be removed. The removal is to be effective on the date the final rule becomes effective.

EFFECTIVE DATE: The rule is to be effective July 6, 1981. The removal of refund contingencies imposed in all cases decided subject to the Order Establishing Interim Procedures, issued June 8, 1979 under Docket Nos. R-424 and R-446 is to be effecitve July 6, 1981.

FOR FURTHER INFORMATION CONTACT:

Ronald L. Rattey, Office of Regulatory Analysis, Federal Energy Regulatory Commission, Room 3000F, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357–8186;

Robert F. Shapiro, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8000, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357–8455;

Fredrick L. Jaffe, Office of the General Counsel, Federal Energy Regulatory Commission, Room 8100J, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357–8363;

Russell E. Faudree, Jr., Office of the Chief Accountant, Federal Energy Regulatory Commission, Room 3410, North Building, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357–9188.

SUPPLEMENTARY INFORMATION:

In the matter of tax normalization for certain items reflecting timing differences in the recognition of expenses or revenues for ratemaking and income tax purposes (Docket No. RM80–42), accounting for premium, discount and expense of issue, gains and losses on refunding and reacquisition of long-term debt, and interperiod allocation of income taxes (Docket No. R–424), amendments of the uniform systems of accounts for classes A, B and C public utilities and licensees and natural gas companies: deferred income taxes (Docket No. R–446); Order No. 144.

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Commission Findings and Orders

Final Rule

Appendix A—List of Commenters in Docket No. RM80-42

I. Introduction

A. Background

The Federal Energy Regulatory Commission (Commission)[1] amends Part 2 of its regulations to require tax normalization for the tax effects of certain (hereinafter "certain" or "miscellaneous") timing difference transactions (other than those specifically excluded as discussed below) in rates of electric utilities and interstate natural gas pipelines (hereinafter "utilities and pipelines" or "utilities"). The final rule also codifies the existing Commission ratemaking practice of adjusting rate base for accumulated deferred income taxes. Finally, the final rule requires adjustments in the deferred taxes for utilities' and pipelines' cost of service for two types of circumstances: (1) when inadequate or excessive provision for deferred taxes has been made for the tax effects of timing difference transactions within the scope of this rulemaking that had previously been given flow-through treatment; and (2) when inadequate or excessive provision for deferred taxes has been made as a result of changes in tax rates. These latter cost of service adjustments to deferred taxes are required to be made by the applicant either by following a Commission-approved ratemaking method made specifically applicable to the utility or pipeline or by developing in its next rate case a method for handling any excesses or deficiencies that might exist in the deferred tax reserves because of prior flow-through treatment of timing difference transactions or because of tax rate changes.

The final rule differs from the proposed rule in several respects. The proposed rule would have allowed utilities to elect to use tax normalization for the timing difference transactions covered by the rule; but once the election was made, all miscellaneous timing difference transactions covered would have to be normalized. This provision was intended to prevent an applicant's picking and choosing among timing difference transactions in such a way that tax normalization of a transaction would only be used if it immediately benefited the utility or pipeline. As explained in more detail below (Section III), the final rule responds to the objections of many parties to the election provision and instead requires tax normalization of all timing difference transactions covered by the rule. Companies may, however, combine the timing difference transactions for purposes of tax normalization to prevent unnecessary and costly bookkeeping for insignificant individual timing difference transactions.

The final rule also differs from the proposed rule by giving more specificity to the ratemaking treatment of the tax effects of timing difference transactions that had previously been flowed through and of the effects of tax rate changes. The proposed rule would not have permitted any adjustments to deferred taxes for deficiencies or excesses caused by reversals of past flow-through transactions or tax rate changes unless the applicant had adopted a Commission approved method for making such adjustments. The final rule requires an adjustment to be made in the applicant's next rate case following the applicability of the rule. Other minor, conforming changes were made in the final rule. These changes are discussed in detail, below, in Section III.

The rule, of course, leaves undisturbed the ability of the parties to reach a settlement on any of the issues covered by the rule.

This final rule culminates a long procedural history that was detailed in the Notice of Proposed Rulemaking [2] and is summarized here. In 1975, the Commission issued Order No. 530.[3] The order dealt with the tax effects of certain timing differences that had not been covered by previous Commission orders and opinions.

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[1] The term "Commission" refers to the Federal Power Commission (FPC) with respect to actions taken prior to October 1, 1977, and to the Federal Energy Regulatory Commission (FERC) with respect to any actions on or after that date.

[2] "Tax Normalization for Certain Items Reflecting Timing Differences in the Recognition of Expenses or Revenues for Ratemaking and Income Tax Purposes," Docket No. RM80-42, 45 F.R. 22053 (April 3, 1980) (hereafter cited as Notice).

Timing differences that were excluded from Order No. 530,[4] and similarily are excluded from coverage under the final rule, are:

(1) Differences that result from the use of accelerated depreciation.

(2) Differences that result from the use of Class Life Asset Depreciation Range (ADR) tax provisions.

(3) Differences that result from the use of accelerated amortization provisions on certified defense and pollution control facilities.

(4) Differences that arise from recognition of extraordinary property losses as a current expense for tax purposes but as a deferred and amortized expense for book purposes.

(5) Differences that arise from recognition of research, development, and demonstration expenditures as a current expense for tax purposes but as a deferred and amortized expense for book purposes.

(6) Differences that result from different tax and book reporting of deferred gains or losses from disposition of utility plant.

(7) Differences that result from the use of the Asset Guideline Class "Repair Allowance" provision of the Internal Revenue Code.

(8) Differences that result from recognition of purchased gas costs as a current expense for tax purposes but as a deferred expense for book purposes.

In Order 530, the Commission expressed a general ratemaking policy in favor of tax normalization but contemplated that the decision to apply tax normalization would be made in individual cases.

On rehearing, the Commission in Order 530–A [5] stated that in each rate case a "tax deferral" rather than a "tax savings" would have to be proved by the rate applicant before tax normalization for a particular class of items could be allowed. The Commission found that this requirement was imposed by previous court opinions.

In Order No. 530-B,[6] the Commission, in a reassessment, found that the only legal bar to the adoption of tax normalization was the identification of a transaction as a permanent difference rather than as a timing difference. In this last order of the 530 series, the Commission adopted a ratemaking policy permitting normalization of the tax effects of all miscellaneous timing differences.

The instant proceeding was initiated in response to the remand of Order No. 530–B by the United States Court of Appeals for the District of Columbia Circuit.[7] The specific points raised by the court on remand and the Commission's final response are contained in Section I–B, below. The Notice of Proposed Rulemaking in the instant docket attempted to resolve what the Commission understood to be the difficulties raised by the court on remand. Both initial comments and reply comments on the proposed rule were requested.

Pursuant to issuance of the Notice, the Commission has received and reviewed numerous comments (initial and reply) both favoring and opposing the proposed tax normalization policy. The list of commenters is attached as Appendix A. Together with the staff study that accompanied the Notice, the comments provide a substantial basis upon which the Commission may reach a reasoned determination of the appropriate policy to best carry out its statutory goal of establishing "just and reasonable" rates. After careful evaluation of this material, the Commission adopts this final rule requiring tax normalization for the tax effects of miscellaneous timing difference transactions.

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[3] "Order Implementing that Portion of Docket No. R–424 Relating to Interperiod Allocation of Income Taxes and Docket No. R–446, to Achieve Interperiod Allocation of Income Taxes," Docket Nos. R–424 and R–446 (issued June 18, 1975).

[4] Item number seven listed below was not specifically excluded in Order No. 530, but is excluded in this final rule.

[5] "Order Denying application for Rehearing and Clarifying Prior Order" (issued January 19, 1976).

[6] "Order Revising Prior Orders" and "Order Denying Rehearing of Order No. 530-B" (issued July 6, 1976 and September 8, 1976).

[7] *Public Systems, et al.* v. *FERC*, 606 F.2d 973 (D.C. Cir. 1979), *reh. den.* March 30, 1979.

In general, the Commission is pleased with the quality of the comments submitted and appreciates the time and effort devoted by the parties to this proceeding. The debate over tax normalization versus flow-through treatment of timing difference transactions has continued for more than two decades. This proceeding was first initiated in proposed Commission rulemakings issued almost ten years ago. It is probably unrealistic to believe that this debate will end with the issuance of this final rule. Nevertheless, the Commission feels confident that it has afforded all parties ample opportunity to present their views, that these views and the arguments and evidence supporting them have been fully presented in this proceeding, and that, on balance, the scale tips very persuasively toward requiring tax normalization for miscellaneous timing difference transactions as a general rule for utilities and pipelines under the Commission's jurisdiction.

The following Section II reviews the comments and responses to the issues raised. Except as otherwise described, the Commission adopts and incorporates by reference in this final rule the discussion in the Notice concerning the relative merits of tax normalization and flow-through.

In addition to issuing the final rule in Docket No. RM80-42, the Commission in this order makes another finding concerning tax normalization of the tax effects of these miscellaneous timing difference transactions. After Order No. 530-B was remanded, the Commission issued an Order Establishing Interim Procedures in Docket Nos. R-424 and R-446 [8] to alleviate the procedural uncertainty among presiding law judges and litigants about the timing difference transactions covered under Order No. 530-B. In that order, the Commission declared that:

> any final decision which requires a refund of amounts otherwise in excess of the just and reasonable rate level shall not require a refund of that portion of the rate related to interperiod tax allocation [tax normalization]. That portion shall continue in effect, subject to refund, pending a final order in these dockets.

Since the Commission finds in this proceeding that tax normalization is the preferred ratemaking policy for the tax effects of the timing difference transactions covered in this proceeding, the Commission determines that tax normalization under the Order No. 530-B policy is found to produce rates that are just and reasonable. Dockets Nos. R-424 and R-446 are therefore consolidated with the instant Docket No. RM80-42. In addition to the final rule for Docket No. RM80-42, the Commission orders that for rates directed to be collected subject to refund pending the outcome of a final order in Docket Nos. R-424 and R-446 the refund contingency shall be removed as of the date that the final rule issued in this proceeding becomes effective.

B. Compliance With the Remand of Order No. 530-B

The court in *Public Systems* [9] remanded Order No. 530-B and related orders to the Commission for further action. The court found that the Commission had failed to "assess the consequences of its action for the industry," and to "indicate 'fully and carefully' the purposes behind the order." [10]

This section is intended to show how the Commission has responded to the concerns of the *Public Systems* court. The Commission believes it has fully considered and responded to the court's concerns.

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[8] Issued June 8, 1979.

[9] 606 F.2d at 983.

[10] *Id.* at 980.

1. **Purpose and Goals of the Rule.** The *Public Systems* court noted that Order No. 530-B rested on general policy considerations and stated that the Commission had failed to adequately explain the purposes and goals underlying its decision. The court stated that the only policy goals mentioned in the order would apply to a generic flow-through policy as well as to a tax normalization policy.[11]

The Commission considered a wide variety of factors in its evaluation of the tax normalization and flow-through policies.[12] We find that the record in this proceeding overwhelmingly supports a tax normalization policy. We find that tax normalization more appropriately comports with sound regulatory principles and with the public interest than flow-through.

As reiterated throughout this rule, tax normalization better achieves the goals of equity and fairness in rates than does flow-through. The primary rationale for tax normalization is matching: the recognition in rates of the tax effects of expenses and revenues with the expenses and revenues themselves. In terms of expenses only, this means that tax normalization matches tax benefits with cost responsibility. Tax normalization allocates the tax benefits of an expense to the same time periods that the expense itself is allocated. The Commission finds (in Section II-B) that this matching results in a more equitable interperiod allocation of tax costs to customers than does flow-through. Flow-through, through its inequitable allocation of tax costs over time, is found to distort the Commission's pricing policies.[13]

The Commission also finds that its tax normalization policy balances its obligations to ensure reasonable rates to ratepayers and to maintain the financial integrity of the public utilities and natural gas pipelines it regulates. In Section II-C, the Commission finds tax normalization to be more properly cost-based than flow-through. The Commission finds (in Section II-C and II-D) that tax normalization meets the "actual taxes paid" principle from both policy and legal standpoints. Overall, tax normalization is found to meet the just and reasonable rate standards of the Federal Power Act (FPA) and Natural Gas Act (NGA). (*See* Section II-H).

The Commission also finds that tax normalization is likely to result in rates and revenues that are more stable over time than flow-through (Section II-J.4.); and the Commission finds (Section II-J.5) that no adverse efficiency incentives are given to companies by the use of tax normalization.

Finally, the Commission finds that the issuance of this final generic rule requiring tax normalization will eliminate the ongoing controversy and attendant uncertainty regarding the appropriate treatment of miscellaneous timing difference transactions in Commission rate proceedings. The resulting administrative efficiency and clarity should benefit consumers, regulated utilities and the Commission.

2. **Items Covered by the Rule.** The court in *Public Systems* criticized the Commission for not specifying all of the transactions that would be covered by the tax normalization policy and for inadequately discussing the seven examples that were given.[14]

The Commission's rule requires tax normalization of the tax effects of "miscellaneous" timing difference transactions. The Notice referred to the list of examples of timing differences identified in Order No. 530.[15] An appendix to the Notice listed nineteen additional examples of timing differences that would be covered by

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[11] *Id.* at 980-981.

[12] This consideration is demonstrated in the staff study attached to the Notice and in the Commission's review and evaluation of the comments contained herein. Except to the extent specifically described, the Commission adopts the staff study as part of this final rule.

[13] *See* Section II-B, below, and Notice at 31, 45 F.R. at 22059.

[14] 606 F.2d at 981.

[15] Notice at 35, 45 FR 22059.

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the rule.[16] Commenters were also asked to identify any additional timing differences that would be covered by the rule.[17] Commenters brought no additional timing differences to the Commission's attention. We believe that we have identified the major timing differences covered by this rule.

The Commission believes, in addition, that the definition of timing differences in the rule is clear and specific enough so that parties to rate proceedings can readily identify those revenue and expense transactions that qualify for tax normalization treatment. Accordingly, the Commission believes it is not necessary to specify every single type of revenue and expense transaction that might give rise to timing difference covered by the rule.

As to the court's concern that the Commission discuss, in some detail, each of the types of transactions covered by the rule, the Commission believes it has fully responded. The Commission explained in the Notice that there are four basic types of transactions that give rise to a timing differences:

(1) *expenses* that are recognized for tax filings in periods *prior to* when they are recognized in rates;

(2) *expenses* that are recognized for tax filings in periods *later than* when they are recognized in rates;

(3) *revenues* that are recognized for tax filings in periods *prior to* when they are recognized in rates; and

(4) *revenues* that are recognized for tax filings in periods *later than* when they are recognized in rates.

The first and fourth types reduce tax liability currently and raise it later. The second and third types raise tax liability currently and reduce it later.

The Commission also explained that there is no difference in the principles underlying the application of tax normalization to the different types of transactions.[18]

3. Impacts of the Rule on Industry and Consumers. The *Public Systems* court criticized the Commission for failing to indicate the impact on consumers and industry of adopting tax normalization and for providing no statement as to the financial resources at issue. The Commission believes it has throughly assessed the impacts of its rule on industry and consumers in this proceeding. Upon review of the staff study's impact analyses and the comments received thereon, the Commission finds that the staff study provides reliable data and analyses in this regard and adopts its findings.

Based on the Commission's review of staff's impact analyses and of the comments received on the rule's impacts (Section II–I), the Commission finds:

(1) Staff's rate impact estimates are reliable. These data show that tax normalization may, at least initially, result in higher rates than flow-through. However, these impacts are not substantial. Since rates under tax normalization more equitably allocate tax costs over time, these impacts show the extent to which the continued use of flow-through causes current ratepayers to be subsidized by future ratepayers.

(2) Tax normalization acts as a stabilizing force on utility cash flows. Tax normalization tends to improve a utility's internal cash flow when the need is greatest and to decrease it when the need is less. As a result, the rule would lessen a utility's reliance on capital markets.

(3) Tax normalization does not inherently give utilities (or, more importantly, their stockholders) an opportunity to earn a rate of return in excess of that nominally allowed by the Commission.

(4) Tax normalization may have a favorable impact on the cost of capital to utilities vis-a-vis flow-through.

With respect to the rate impacts, the Commission believes it is worthwhile repeating the summary of the staff study estimates provided in the Notice. It should be noted that while the final rule is different from the proposed rule in that tax normalization is made a requirement rather than an election, the staff rate impact estimates are still applicable since they assumed that all utilities would elect tax normalization.

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[16] Notice at Appendix C, 45 FR at 22110.

[17] Notice at 54, 45 FR at 22063.

[18] Notice at 11–13, 45 FR at 22055

The Commission also notes that despite a specific request for data on the impacts of timing differences not quantified in the staff study, only one substantive comment was received on this issue—relating to intangible drilling costs.[19] The data upon which to evaluate the thoroughness of staff's analysis are publicly available, and no commenter has shown any significant deficiency in staff's analysis.

Staff quantified the rate impacts of the following types of timing differences:[20]

1. Differences that result from recognition of the following items as current expenses for tax purposes and as capitalized and amortized expenses for ratemaking purposes:

(a) the interest component of the Allowance for Funds Used During Construction (AFUDC);

(b) construction-related pensions; and

(c) construction-related taxes.

2. Differences that result from the use of different depreciation lives for taxes and ratemaking.

3. Differences that result from recognition of regulatory commission cost as a current expense for tax purposes and as an expense amortized over a number of years for ratemaking.

In the Notice, the Commission summarized staff's rate impact analyses as follows:

> With respect to the items listed above for which the staff study did quantify impacts, assuming no difference in the cost of capital for flow-through and normalization, the results indicate that electric utility rates, on average, would have risen 3.3 percent and gas pipeline rates 0.2 percent over flow-through rates in 1976 had a utility switched from a flow-through policy to a normalization policy. For 1980, the maximum impacts are estimated to be about 2.2 percent for electric utilities and 0.1 percent for gas pipelines. These impacts are generally projected to diminish over the next 20 years, with normalized gas pipeline rates falling below flow-through rates during this time span. In the year 2000, normalized rates are projected to be less than flow-through rates in the natural gas pipeline industry and to be a maximum of about 0.9 percent above flow-through rates in the electric utility industry. This differential for electric utilities continues past the year 2000.
>
> The actual dollar impacts (in constant 1980 dollars) of normalization versus flow-through also are set forth in the staff analysis for the base and life depreciation timing differences (items 1 and 2 listed above). In 1976, jurisdictional required revenues for the gas pipeline industry would have been $28 to $32 million higher (depending on the assumed growth rate) under normalization than under flow-through if all pipelines had switched to normalization of the base and life differences. By 1980, the jurisdictional required revenues are estimated to be $18 to $20 million higher under normalization and to be $4 to $6 million higher by 1990. By the year 2000, jurisdictional required revenues for gas pipelines are projected to be $5 to $10 million *less* under normalization than under flow-through. After the year 2000, the trend of lower revenues under normalization increases.
>
> For electric utilities, jurisdictional required revenues would have been $183 to $234 million higher (depending on the growth rates and still in constant 1980 dollars) in 1976 if utilities had switched to normalization from flow-through for the base and life differences. In 1980, the jurisdictional required revenues would be $149 to $183 million higher under normalization than under flow-through, and by the year 2000, normalization rates would be $58 to $148 million higher than flow-through rates. While the highest estimated dollar impact of $234 million in 1976 appears large, as noted earlier it represents only a little over 3 percent differential between normalized and flow-through rates. For the high growth case of 14 percent, the staff analysis projects total (jurisdictional and non-jurisdictional) electric utility revenues to be $85 billion in 1980, of which approximately 10 percent represents jurisdictional revenues.[21]

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[19] *See* Section II-I, below.

[20] In addition, the study discussed the impact on rates of applying tax normalization to plant removal costs, especially with respect to nuclear generating plants and offshore pipeline facilities. The Commission believes that while these impacts are likely to be significant they are still uncertain.

[21] Notice at 36-38, 45 F.R. at 22060 (cites and footnotes omitted).

The Notice goes on to qualify these results on impacts since they do not reflect any cost of capital differential between tax normalization and flow-through. The staff study estimated the effects of a range of cost of capital differentials.[22] Finally, the Commission does not believe that quantification of any other timing differences covered by this rule would substantially affect the overall impacts.

4. Tax Savings versus Tax Deferral.

The court in *Public Systems* stated that as to the examples of timing differences listed in Order No. 530, there was nothing to support the Commission's implicit conclusion that there would be no "tax savings."[23]

This issue was discussed extensively in the Notice[24] and staff study.[25] The Commission's analysis of the comments on both the legal and policy aspects of this issue is contained in Section II–E below. The Commission finds that a tax normalization policy will not cause utilities or their investors to realize a permanent or pure tax savings. Under some circumstances, however, tax normalization may create continual tax deferrals which we find are not permanent tax savings since they do not confer a permanent tax benefit on utilities or their investors. We further conclude that a finding of evanescent versus continual tax deferral should not be the determinative factor in a decision to adopt a policy of tax normalization or flow-through.

5. Price Squeeze.

The *Public Systems* court faulted the Commission in Order No. 530–B for giving no reason or rationale for the Commission's statement that it would decide the price squeeze implication for tax normalization on a case-by-case basis.[26] As explained more fully in Section II–G.2 below, and as stated in the Notice,[27] we continue to believe that we cannot conclude, as a generic matter, that the tax normalization rule will occasion any undue disparity between relevant wholesale and retail rate, even in instances where state commissions proscribe the use of tax normalization.

Certainly, where the Commission finds that a price squeeze has been demonstrated, the impact, if any, of tax normalization must be considered. If undue discrimination is found to exist, the Commission may consider the denial of tax normalization as one of the available remedies for reducing or eliminating the undue discrimination, just as other costs of service elements initially required by Commission regulations could be adjusted to remedy undue discrimination. In contrast to the policy expressed in the Notice, the Commission retains the option of denying tax normalization even if the undue discrimination is not directly caused by differing state/federal treatment of tax normalization of miscellaneous timing differences.

II. Analysis of Comments: Legal and Policy Considerations

A. Summary of Conclusions

In this section, the Commission reviews the comments and reply comments and discusses the legal and policy issues involved in requiring tax normalization of the tax effects of miscellaneous timing difference transactions as a general rule. The answer to the central question of this rulemaking proceeding—whether tax normalization or flow-through provides the most appropriate way to handle timing differences in ratemaking—is complex. Much confusion and controversy surround the discussion of this issue.

The central rationale for tax normalization is that tax normalization matches the recognition in rates of the tax effects of the costs and revenues of utilities to the recovery in rates of the associated costs and revenues themselves. In terms of expenses only, tax normalization matches tax benefits with cost responsibility. The Commission finds that this matching concept leads to fair and equitable results both to the regulated entities and to their customers. Equity is also achieved over time by the use of tax normalization. None of the comments to the Notice have dissuaded the Commission from continuing to accept the matching and equity principles as the underlying policy reasons for tax normalization. Section II–B discusses these concepts more fully.

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[22] Appendix A of Notice at 107–111, 45 F.R. at 22099–22103.

[23] 606 F. 2d at 981. (The court apparently equated "tax savings" with constant or growing balances in accumulated deferred taxes.)

[24] Notice at 15–16, 41–44, 45 F.R. at 22056, 22061.

[25] Appendix A of Notice at 23–24, 47–59, 112, 45 F.R. at 22069–70, 22078–81, 22103.

[26] 606 F. 2d at 980–81.

[27] Notice at 45–46, 45 F.R. at 22062.

A major controversy—both in policy and in the law—revolves around the so-called "actual taxes paid" doctrine. Several commenters who opposed the proposed rule interpreted "actual taxes paid" as requiring the tax allowance in rates charged during each period to equal the taxes actually paid in each period. Application of this interpretation would treat tax costs differently from other costs incurred by utilities.

The Commission believes that there is no rational basis for this interpretation. All costs should be allocated among customers and over time in a manner that matches the burdens of costs with the benefits received. While no system has been designed that does this precisely for all costs, at least with respect to tax costs, normalization rather than flow-through better achieves this proper end result. Also, as long as rates recover only the total tax cost incurred over time, and no more, then the "actual taxes paid" principle is met. Section II–C discusses the cost basis for tax normalization that the Commission believes is appropriate, and Section II–D reviews the legal basis for finding tax normalization consistent with the "actual taxes paid" doctrine.

Another source of confusion is the rhetoric that has developed over the years in the tax normalization versus flow-through debate. Phrases like "phantom taxes" and "permanent tax savings" raise concern that the issue is one of cost determination rather than cost allocation. Tax normalization is said to place "phantom taxes" in electric and gas bills. The Commission recognizes that "deferred taxes" are no more or no less "phantom" than are the costs which generated them. These costs are approximately twice the size of the deferred taxes and cannot be recovered in rates without the concomitant recovery of so-called "phantom" taxes.

In addition, tax normalization of timing differences is argued to result in "permanent tax savings" to utilities that are growing. Yet, utilities cannot achieve such "permanent savings" without at the same time incurring a "permanent loss" through the non-recovery of associated costs which are approximately twice as large. This issue is discussed at length in Section II–E, wherein both the legal and policy perspectives on "permanent tax savings" are sorted out. Past treatment of this issue by the Commission and the courts is reviewed and distinguished from the Commission's current policy as expressed in the current rulemaking.

A final source of confusion in the comments arose from the staff report that was appended to the Notice. In that report, the effects of normalization were analogized to a customer loan. The problems with this "analogy" are discussed below in Section II–F. The Commission finds no reasonable basis for concluding that customers actually provide a loan to their utility under tax normalization.

Two legal issues have been central to the current controversy and were raised by the commenters in this rulemaking. One issue is whether the Commission should treat tax normalization of the tax effects of miscellaneous timing differences as a general rule or whether individual circumstances of the firms and their customers are so unique that the decision should be determined on a case-by-case basis. A second legal issue raised is whether a tax normalization rule is consistent with the just and reasonable standards in the Federal Power and Natural Gas Acts. This latter question is closely linked with the contentions that tax normalization creates "permanent tax savings" and violates the "actual taxes paid" doctrine.

The Commission concludes, in Section II–G, that it has discretion to require tax normalization of the tax effects of miscellaneous timing differences by general rule rather than by case-by-case adjudication. The regulatory principle of matching tax effects of costs and revenues to their associated costs and revenues is an equitable principle that does not vary under an individual firm's circumstances. The Commission does not, however, believe that tax normalization must be applied in cases where the Commission has found price squeeze to be present. The tax normalization requirement may be removed to remedy undue discrimination between wholesale and retail customers.

In Section II–H, the Commission finds that tax normalization is just and reasonable under the Federal Power and Natural Gas Acts.

In the Notice, the Commission addressed the impacts its proposed tax normalization policy would have on rates, cash flow, rates of return and costs of capital as analyzed in the staff study attached to the Notice. The comments to these estimated impacts are reviewed in Section II–I; the Commission finds its staff's original analyses to be reasonable and equally applicable to the final rule.

The terms "phantom taxes" and "permanent tax savings" have often been employed to advance the argument that utilities and, more important, their stockholders are earning excess profits under tax normalization. Since deferred tax accounting does not permit utilities to transfer accumulated deferred taxes to common equity accounts for the benefit of stockholders, the Commission reiterates its earlier statement in the Notice that tax normalization does not create excess profits. This is discussed more fully in Section II–I.3.

The remaining section of this part, Section II–J, discusses other comments raised to the Notice and presents the Commission's response to these comments. Specifically, this section addresses: normalization of the tax-on-tax effect; rate base levelization; contributions in aid of construction; revenue and rate stability; efficiency incentives; tax rate changes; and depreciation of plant financed by deferred taxes.

B. Matching and Equity

The Commission stated in the Notice that the rationale underlying tax normalization is different from that underlying flow-through. Tax normalization is based on the matching principle. According to the matching principle, the tax reducing effect of an expense [28] is allocated to the same customers who pay the expense during the same period. When rates are set so as to permit a utility to recover an expense, the tax reducing effect of that expense is also recognized. When recovery of an expense is deferred or prepaid, so too is the tax reducing effect of that expense. In this way, normalization achieves an equitable allocation of costs between time periods. [29]

Flow-through is based primarily on the so-called "actual taxes paid" principle. [30] This principle, as interpreted by flow-through proponents, states that customers should be charged, in each period, only the income taxes actually paid by the utility in that period. The matching here is between the cost of service tax allowance and the IRS-determined tax liability. The problem with this approach is that it causes the interperiod allocation of taxes in rates to be solely dependent upon tax regulations rather than upon the regulatory principle of matching costs with benefits. The result is an inequitable allocation of costs between time periods. This inequity is illustrated in the Commission's example in the Notice of how flow-through distorts prices over time:

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[28] As explained in the Notice, timing differences can arise from expense or revenue transactions that are either prepaid or deferred in rates. For discussion purposes, the differences between the two policies can be most easily understood with reference to an expense transaction that creates a tax deferral in rates.

[29] As the Commission, in the Notice, notes: "[U]nderlying the equity argument is the concept of 'used and useful' property. . . . If current customers are paying the expenses associated with a given piece of equipment or property, because they are receiving service from it, they also should be receiving the benefits of the tax deductions arising from the associated expenses." Notice at 28–29, 45 F.R. at 22058.

[30] *See* Section II–C for a discussion of alternative interpretations of this principle. In that section, we explain why tax normalization results in rates that are cost-based. In Section II–D we explain that tax normalization is also consistent with the "actual taxes paid" principle.

> [I]f the Commission has determined that a reasonable allocation for the recovery of a $100 expense incurred in year 1 is $50 in each of years 2 and 3, then rates in year 1 should be unchanged and rates in years 2 and 3 should be increased by $50. This is essentially what occurs under a normalization policy. A flow-through policy, however, produces a very different result. Because income received in the form of a tax allowance represents additional taxable revenues, rates under a flow-through policy actually would be reduced in year 1 by $100 and increased by $100 in each of years 2 and 3.[31]

While this example is for a single timing difference transaction, it also applies to many transactions occurring simultaneously and over successive periods since the effects of more than one transaction is simply the sum of the effects of the individual transactions.

None of the parties in this proceeding have persuaded the Commission that the above reasoning is wrong. While many comments discussed the comparative equity in the effects on rates of tax normalization and flow-through, none of the arguments raised were without flaws. These arguments and their flaws are discussed immediately below. The commenters also implicitly or explicitly argued that other factors, such as an immediate adverse impact on rates, should be given more weight. We continue to believe, however, that, from a policy perspective, substantial weight should be given to the long term equity considerations that overwhelmingly favor tax normalization over flow-through.

Three general types of equity issues were raised in the comments:

(1) Equity between present and future ratepayers or interperiod equity;

(2) Equity between different classes of ratepayers; and

(3) Equity between ratepayers and stockholders.

The commenters raised the first type of equity issue (interperiod equity) in several ways. It was argued that since all other costs associated with a given plant are not spread evenly over its life, there is no need to spread tax costs evenly. Indeed, it was argued that flow-through would counteract the declining rates caused by the declining rate base and tend to even out the cost burden on ratepayers over a plant's life. This rate base levelization issue is addressed in Section II–J.2, below. There the Commission finds that rate levelization is not a goal of the proposed tax normalization rule and that, even if it were, flow-through of the significant items covered by the rule would not achieve this result.

A second interperiod equity criticism of tax normalization is based on the allegation that the normalization is incomplete since it does not require normalization of the tax-on-tax effect. This criticism is addressed in Section II–J.1 where it is concluded that such a proposal errs in its attempt to treat the deferred tax expense, a non-deductible expense, as a timing difference transaction.

Another interperiod equity criticism of tax normalization is based on the assumption that it requires customer-contributed capital. Commenters argued first that under conditions of growth the utility completely eludes repaying the customer loan and, second, that there is no coincidence between the customers who provide the loan and those who receive the return of the principal and interest on such loan. The Commission addresses this issue in Section II–F, below, where the concept of a customer loan under tax normalization is rejected.

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[31] Notice at 31, 45 FR at 22050 (footnote omitted).

Several commenters recognized the interperiod inequity generated by flow-through that the Commission noted in its proposed rulemaking. Commenters pointed out that flow-through generally involves putting off the recovery of current tax costs to the future and that there is no more justification for this than there is for putting off the recovery of current depreciation costs. Another commenter argued that, because of this cost postponement, flow-through benefits (or subsidizes) current customers at the expense of future customers.

The Commission agrees with the commenters who contended that flow-through benefits wholesale customers who intend to build their own generating facilities or who otherwise intend to shift suppliers in the near future. This results when flow-through recognizes the tax benefits of expenses in rates prior to the recognition of the expenses themselves. Further, as several reply commenters emphasized, each dollar of tax benefits flowed through to customers prior to the cost of service recognition of the associated expense will require two dollars in additional revenue requirements when the expense is recognized. Future customers must pay both the expense and an additional amount equal to the expense to defray taxes on the resultant higher revenue requirements.

The second type of equity issue raised in the comments dealt with the treatment of different classes of ratepayers at any point in time. Tax normalization is criticized as having a disproportionate impact on low income consumers who tend to spend a greater portion of their income on energy. This criticism is aptly rebutted in the reply comments. The allegedly adverse income redistribution effects of tax normalization arise from the implicit assumption that the policy is not a conceptually valid and equitable method for computing cost of service. The Commission finds no support for this assumption.

Virtually all changes in Commission policies have income redistribution effects. The Commission is not inclined to decide policy *solely* on whether or not income is redistributed. However, to the extent that the change from a flow-through to a tax normalization policy affects the distribution of the burdens on consumers of utility tax costs and thus the income distribution of consumers, the Commission finds it justifiable. This is because tax normalization is more properly cost-based than flow-through and because it more equitably allocates tax costs to consumers over time than does flow-through.

The third equity issue involves allegations that tax normalization causes ratepayers to subsidize investors. Since investors are not permitted, under the Commission's ratemaking policies, to appropriate any of the benefits arising from timing difference transactions, this allegation is rejected. The Commission addresses this concern in detail in Section II–I.3, below.

C. Cost Basis for Tax Normalization

Several of the commenters criticized tax normalization as not being cost-based. Others expressed the opposing view that tax normalization is cost-based and flow-through is not. These divergent views arise solely from differences in the definition the parties attach to the term "cost-based".

If "cost-based" merely means that the allowance in rates for a particular cost over the life of the utility should cover only the outlays made by the utility for that cost and no more, then both tax normalization and flow-through are cost-based. Neither policy inherently permits a utility to recover over its life more than its actual tax outlays.

For those who argue that "cost-based" means that the cost of service allowance for a particular cost should cover only the actual cash outlay made by the utility in *each* period, then flow-through is cost-based and tax normalization is not. Flow-through allocates taxes on an "as paid" basis while tax normalization does not. Flow-through, for example, would allocate to one period the tax reducing effects of certain construction-related costs (that are not included in current rates), thereby lowering the tax allowance below what it would be absent the construction activity.

On the other hand, for those who believe that "cost-based" means that the allowance for a particular cost should equal, in each period, the cost associated with the goods and services provided in that period, then tax normalization is cost-based. The Commission adopts this latter definition.

The basic difference between tax normalization and flow-through is in the timing of recognition of revenues and expenses in computing the cost of service tax allowance. Flow-through recognizes timing difference transactions for the purpose of computing the tax allowance in time periods other than when those transactions are themselves recognized in the cost of service. In so doing, it arbitrarily changes the tax allowance from that which is associated with the allowance for return on equity even though it is the equity return over time that gives rise to tax liabilities.

Tax normalization, however, reflects as income tax deductions or additions only those expenses and revenues that are themselves reflected in the cost of service. The tax cost associated with the goods and services provided in a particular period, *i.e.*, what the Commission considers the "current tax cost" of that period, should be related to the equity return allowed since it is the equity return over time that gives rise to tax liabilities. The tax allowance under tax normalization is related to the equity return allowance. The tax allowance under flow-through is not.

As the Commission stated in its Notice, the basic issue in this proceeding involves the interperiod allocation in rates of a cost, specifically, the income taxes paid by utilities. Taxes, like other costs, may be more properly chargeable to periods other than when they are actually paid.[32] Tax normalization achieves what the Commission finds is the more proper allocation of taxes over time by using the provision for deferred taxes as a mechanism for setting the tax allowance at the level of current tax cost.

This view of how tax normalization is cost-based (and flow-through is not) may be made clearer by reference to the numerical illustrations in the staff study.[33] In Case I (the Base Case with no timing differences), the cost of service in each of the three years shows an after-tax equity return allowance of $200 and an associated tax allowance of $200. A pretax equity return allowance of $400 multiplied by a 50 percent tax rate results in associated taxes of $200. Tax normalization (Case IV) results in the same annual tax allowance of $200 coinciding with the same after-tax equity return allowance of $200. The equity return allowance is intended to cover the cost of the equity capital used to finance rate base, a direct cost in providing services. The tax liability arises from this cost and, in both of the above cases, the tax allowance is directly proportional to the equity return.

In contrast, under flow-through (Case V), the tax allowance is totally unrelated to the equity return allowances. The after-tax equity return allowance in each of the three years remains at $200. However, the tax allowances in years 0, 1, and 2 are $100, $250, and $250, respectively. Thus, under flow-through, the tax allowance diverges from the equity return allowance and, by implication, from the tax costs associated with the goods and services being provided.

The comments contained essentially three arguments as to why tax normalization should not be considered cost-based. First, it was argued that tax normalization violates the so-called "actual taxes paid" doctrine since tax deductions which immediately reduce taxes payable are not immediately recognized in rates. Or, as another commenter stated, tax normalization forces customers to reimburse utilities for costs (taxes) not yet paid.

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[32] For instance, the Commission allocates plant-related costs to the service life of the plant, rather than to the construction period when the costs may have actually been paid by the utility.

[33] Appendix A of the Notice at 11–24, 45 FR at 22067–9.

There are both legal and policy questions involved in these comments, which relate to the so-called "actual taxes paid" controversy. The legal questions are dealt with in the following Section II–D, while the policy questions are handled here.

From one perspective, the disagreement over the "actual taxes paid" doctrine has to do with the meaning of the term "paid". Several commenters opposing tax normalization interpret "actual taxes paid" to mean actual cash outlays to the Treasury. This appears to be the basis for flow-through. In our view, however, "actual taxes paid" refers to the incurrence of a cost in the providing of goods and services to utility customers. As explained above, over the life of any corporation, income taxes are ultimately assessed upon pre-tax earnings to stockholders,[34] and the earnings allowed stockholders in any period depend upon the amount of funds they have invested in the utility's rate base. Thus, income taxes are "actually paid" over time by utilities in a manner proportional to the equity return allowed on rate base. In this way we view tax normalization as meeting the "actual taxes paid" doctrine.

Both of the above-cited comments appear to relate solely to expense-type timing difference transactions that are recognized for tax purposes *prior* to their recognition in rates. If one instead considers the expense-type of timing difference transactions that are recognized for taxes *after* their recognition for rates, such as plant removal costs, the results are opposite to those claimed by the commenters. These tax deductions are recognized in rates before a company can use them for taxes. All other things being equal, tax normalization applied to such items as removal costs reduces the tax allowance during the operating life of the plant below the actual tax outlays of the utility and raises the tax allowance above actual outlays during the year or years of plant removal.

The above comments also neglect the costs that created the reduced tax liability. Tax normalization synchronizes the recognition in rates of the tax deductibility of an expense with the recognition in rates of the expense itself.

The second argument on the cost basis of tax normalization states that tax normalization requires the collection of revenues to meet future taxes which may, in fact, never be paid. This argument involves the concern that a "permanent tax savings" accruing to the benefit of utility stockholders will result from applying tax normalization. As is discussed more fully below (in Section II–I), whether stockholders earn returns in excess of those allowed is not related to adoption of a tax normalization or flow-through policy. The essential difference between the two policies is solely one of allocating tax expenses over time. By constraining the applicability of tax normalization to timing differences and requiring that proper ratemaking and accounting procedures be followed at all times, a utility is precluded from increasing profits from tax normalization.

The third argument raised is that tax normalization treats tax expenses as capital costs, which they are not, and therefore mixes apples and oranges. This criticism misses the mark since the result of tax normalization is to set the tax allowance at the level of current tax cost. Flow-through, on the other hand, involves the allocation of current tax costs to periods other than to those periods in which the expense creating the tax cost is allocated. This policy option is not related to the question of whether an item is a capital cost or an expense, but instead is related to determining the proper timing for the recognition of the tax effects of an expense in a utility's rates.

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[34] This assumes all differences between pre-tax earnings and taxable income arise from timing differences.

All three of the above criticisms of the cost basis of tax normalization imply a cost of service treatment for tax costs different from all other costs. The Commission finds no rational basis for this different treatment. Tax normalization treats taxes in a manner consistent with the treatment of other cost of service elements. Flow-through does not. Like the Commission's treatment of other costs, it is sometimes more appropriate to allocate taxes to periods other than when they are "paid" by the utility. Tax normalization reflects the tax effects of timing difference transactions when those transactions are themselves recognized in the cost of service. For example, the reduction in tax liability resulting from the deductibility of Allowance for Funds Used During Construction (AFUDC) interest expenses is reflected in the cost of service tax allowance when those AFUDC interest expenses are recognized in the cost of service depreciation allowance. This occurs when the plant is placed in service. When the AFUDC interest expenses are fully reflected in rates, the tax deductibility of those expenses is also fully reflected in rates. A similar result occurs for all other timing difference transactions. Thus, when all timing difference transactions have been fully reflected in rates, the tax effects of those transactions will have been fully reflected in rates. Taxes allowed will have been sufficient to cover the tax costs *and no more.*

D. The "Actual Taxes Paid" Principle

Some commenters contend that the Commission cannot legally require tax normalization because it violates the "actual taxes paid" principle. The "actual taxes paid" principle provides that a regulated entity cannot collect through the tax component of its cost of service an amount greater than the taxes it will actually pay. The key case cited in support of this principle is *El Paso Natural Gas Co.* v. *F.P.C.*[35]

Several commenters contend that a tax normalization policy violates the "actual taxes paid" principle because such a policy does not, over the short term, reflect in rates the amount of taxes paid by most regulated entities. Others argue that, to the extent a continual tax deferral is created, the tax component of rates will never reflect the amount of taxes actually paid. In other words, they allege that there will be a permanent tax savings. (*See* Section II–E, below).

The Commission disagrees with these commenters and finds that its approval of a normalization policy is consistent with the "actual taxes paid" principle. Several commenters agree and support the Commission's finding.

The relevant cases make clear that the Commission can legally require tax normalization without violating the "actual taxes paid" principle. In the context of deciding what is the proper regulatory treatment for deferred taxes, the courts have not mandated any particular rate treatment under the "actual taxes paid" principle. Rather, the courts have held that the Commission has wide discretion in choosing between flow-through or normalization, and that that discretion is not inhibited by the "actual taxes paid" principle.[36] The courts have indicated that the key issue for the Commission to decide is whether present ratepayers should receive immediately the full benefit of any IRS tax deduction under flow-through or whether such benefit should be spread out over a period of time under normalization.

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[35] 281 F.2d 567 (5th Cir. 1960), *cert. denied. sub nom. California* v. *F.P.C.*, 366 U.S. 912 (1961). The Court of Appeals stated at 573:

> We think, in short, that there is no statutory authority for the Commission to treat actual savings in taxes to which natural gas companies are entitled any differently than savings in any other cost of service. It is the obligation of all regulated public utilities to operate with all reasonable economies. This applies to tax savings as well as economies of management. The net result of this, of course, is that such savings as are effected are passed on to the consuming public. This we consider to be the natural and necessary consequence of rate regulation.

[36] *See El Paso Natural Gas Co.* v. *F.P.C.*, *supra; Alabama-Tennessee Natural Gas Co.* v. *F.P.C.*, 359 F.2d 318 (5th Cir. 1966); *City of Chicago* v. *F.P.C.*, 385 F.2d 629 (D.C. Cir. 1967); *Memphis Light, Gas and Water Division* v. *F.P.C.*, 500 F.2d 798 (D.C. Cir. 1974).

In *El Paso Natural Gas Co. v. F.P.C.*, 281 F.2d 561 (5th Cir. 1960), the court described tax normalization as "[t]he one exception, if it be an exception" to the doctrine of "actual taxes paid". The court stated that the doctrine was inapplicable to tax normalization since tax normalization involved the deferral of a tax deduction rather than a permanent denial of one. The tax benefits arising from such deduction would be returned to ratepayers through the use of a reserve account.

In *Alabama-Tennessee Natural Gas Co. v. F.P.C.*, 359 F. 2d 318 (5th Cir. 1966), the court upheld the Commission's conversion from normalization to flow-through as a proper exercise of its administrative discretion to choose between competing ratemaking theories. The court stated that if any Congressional intent were relevant to the making of that choice it was—

> * * * A congressional intent that each federal regulatory agency should continue to exercise an informed discretionary authority in accordance with the agency's usual standards in light of the needs peculiar to the particular industry subject to rate regulation.[37]

In *City of Chicago* v. *F.P.C.*, 385 F. 2d 629 (D.C. Cir. 1967) the D.C. Circuit followed the Fifth Circuit's *Alabama-Tennessee* decision and upheld the Commission's decision to flow through tax benefits related to liberalized depreciation as a proper exercise of the Commission's discretion. The Court recognized that the general rule followed by the Commission that "consumers should be charged only the actual liability for Federal income taxes"[38] would not be inconsistent with a tax normalization policy. Indeed, the court noted that tax normalization might be required for reasons of intergenerational equity. The court stated:

> * * * As the Commission pointed out, in some cases normalization of tax deferrals *is required* lest future consumers be compelled to subsidize present consumers being served by the operations accruing tax liabilities. (Emphasis added.)[39]

In *Memphis Light, Gas and Water Division v. F.P.C.*,[40] the D.C. Circuit approved the Commission's adoption of a tax normalization policy and *expressly* held that it did not violate the actual expenditure theory which it equated with the "actual taxes paid" principle. The court noted:[41]

> We find no conflict between the rate increase allowed Texas Gas and the "actual expenditures theory," by which rates of utilities are supposed to reflect actual payments. For while Texas Gas is not currently paying taxes at straight-line rates, it is incurring the liability now to pay increased taxes in the future. Such a method as normalization, whereby current consumers are prevented from forcing future consumers to pay their deferred taxes, does not amount to causing an increase of rates based on fictitious taxes.[61] And the Supreme Court specifically noted in its opinion in this case that normalization was permissible even though it might result in an increase in rates.
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> [61] If normalization were interpreted to have such an effect as suggested by petitioners, it would always violate the actual taxes paid principle.

Thus, the courts have recognized that the Commission has the discretion to permit tax normalization consistent with the "actual taxes paid" principle.

E. Continual Cost and Tax Deferrals: "Permanent Tax Savings"

1. Comments and Responses on Policy Grounds.

The concern that a "permanent tax savings" will accrue to utilities and/or their investors under a tax normalization policy pervades some comments. It is argued that the Commission is attempting to define away the issue by asserting that timing differences "reverse or turn around", and that what the Commission's proposal actually suggests is a "continual deferral of tax savings". It is asserted that as long as a utility is experiencing stable or growing *dollar* investment, the phenomenon of permanent tax savings will occur.

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[37] 359 F.2d at 335 (footnote omitted).

[38] 385 F.2d at 633, *quoting United Fuel Gas Co.*, 12 FPC 251, 265 (1953).

[39] *Id.*

[40] 500 F.2d 798 (D.C. Cir. 1974).

[41] *Id.* at 807 (other footnote omitted).

In response to this concern, other comments included analogies with other costs to show that the "pancaking", over time, of a group of transactions may create the appearance that a utility is continually putting off the payment of a cost. However, this is an illusion caused by the fact that a growing utility will necessarily have greater expenses each year corresponding to greater sales. Each transaction is completed but new higher value transactions replace the old ones. The Commission finds that the analysis given by Appalachian Power Company, *et al.*, with an analogy to "accounts payable", helps make these points clearer:

> * * * The opponents of normalization have confused the accounting of specific individual costs with their prediction of long-range historical patterns. They would lump together all deferrals, regardless of timing differences among them and their application to different service periods; and, if the lump grows, they would maintain that there is no reversal as to any deferral. But determining costs for purposes of ratemaking requires a calculation of pertinent individual costs. The issue is whether *individual* deferrals really do "turn around." The Commission's definition of "timing differences" applies normalization only to true deferrals—to those transactions which really do reverse. As such, there can be no "permanent tax savings" under the proposed rules; and, there can be no continual deferral of any individual "timing difference."
>
> An analogy can be made to the "accounts payable" of a growing firm. Such a firm will have an ever-increasing total of "accounts payable" because it must buy more if it is to sell more. However, since each individual account is paid when due, the fact that the total grows does not mean that there is a "permanent" deferral of any individual debt or that the firm is receiving a "permanent subsidy" from its creditors.[42]

Under the Commission's final regulations, only timing difference transactions qualify for tax normalization treatment and, by definition, every individual timing difference transaction "reverses or turns around." The effect on rates of more than one timing difference transaction is simply the sum of the effects of the individual transactions. It is only when new timing difference transactions of greater value arise that the accumulated deferred tax account grows. The growth of the deferred tax account, however, does not create a permanent savings.

It was also pointed out in the Notice that there cannot be a continual deferral of tax payments by the utility to the IRS unless there is concomitantly a continual deferral in the collection of the associated non-tax costs by the utility from its customers. Assuming a 50 percent tax rate, for every dollar of cost of service tax allowance in excess of "actual taxes paid", the utility has two dollars of "actual non-tax costs paid" in excess of the non-tax cost allowance in rates. For example, the utility must pay out two dollars for AFUDC interest expenses to get one dollar of deferred taxes in rates. From the standpoint of investment, for every dollar of accumulated deferred taxes recorded in a company's books there must concomitantly be recorded two dollars of unrecovered investment in assets. When the utility has recovered in rates all investment dollars associated with timing differences, there will be no deferred tax benefits that have not been reflected in lower rates to customers.

One commenter argued that the associated continual cost deferrals were of no significance in evaluating continual tax deferrals and gave several reasons. The first argument stated that continual cost deferrals are different from continual tax deferrals because the former is part of the capital formation process while the latter involves an expense. The second argument was that investors earn a cash return on the continual cost deferrals while ratepayers are promised only the possibility of lower rates if there is an overall turn around. The third argument was that investors have a substantive assurance that they will be made whole while ratepayers have no such assurance. The commenter argued that investors enjoy increased returns when new plants go into rate base, and if the investor sells his/her shares, the price he/she gets will reflect the buyer's discounting of the higher future earnings. However, ratepayers must remain customers of their utility to obtain the benefits of deferred taxes. The fourth argument alleged that the Commission assumed that the cost deferrals are financed by equity investors, rather than lenders, and contended that equity investors do not actually finance the deferrals until the plant is placed in service.

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[42] Reply Comments of Appalachian Power Company, *et al.* at 13 (emphasis in original). *See also* Reply Comments of El Paso Natural Gas Company at 25–27.

The first argument rests on the idea that taxes are not capital costs and should therefore not be treated as such. As we explained above (Section II–C), however, the tax allowance under tax normalization represents the current tax costs of the utility. Further, as one of the reply commenters stated, the attempt to make a distinction between capital costs and expenses misses "the central point that recovery of the (investor) dollars is [also] continually deferred."[43]

The second and third arguments are based on the view that deferred taxes represent customer-contributed capital, a view that the Commission explicitly rejects (*See* Section II–F). Further, the very fact that ratepayer population changes over time supports tax normalization rather than flow-through, since it is the former policy that treats ratepayers more equitably over time.

The fourth argument concerning the significance of continual cost deferrals is also flawed since it makes a meaningless distinction between equity investors and lenders in funding continual cost deferrals. Both equity investors and lenders are equivalent in that they give the utility the use of their money for a period of time in exchange for a return (or interest) commensurate with risks and both have recovery of their investment (the utility's cost) deferred.

Another criticism expressed in the comments to the proposed policy was that depreciation "base differences" (e.g., AFUDC interest expenses and intangible drilling expenses) were unlike liberalized depreciation timing differences ("method differences"). One commenter stated that this is because base differences involve single period tax deductions which at no time overlap with the ratemaking recognition of the expenses. The commenter concluded from this that there is no crossover point, and therefore, "the construction-related tax benefits at issue in this proceeding are permanent tax savings and not tax deferrals."[44] Another commenter stated that "base differences are items which are capitalized for rate purposes and taken as an expense in a single year for tax return purposes * * * [T]here is *no payback ever and only a pure tax savings is involved.*"[45]

As a number of reply commenters explained, certain expenses may be recognized in separate non-overlapping time periods for ratemaking and tax purposes, but this does not preclude a "turn-around or reversal". The reversal of base differences commences when the plant goes into rate base and the amount of the expense recognized for rate purposes is greater than the amount recognized for tax purposes. The reversal is complete when the plant is fully depreciated and the associated deferred taxes have been fully amortized in rates. Base differences like method differences are timing differences that simply involve the timing of when expenses are recognized as tax deductions for ratemaking and tax purposes. For these reasons, we do not agree with those comments that distinguished "base differences" from "method differences."[46]

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[43] Reply Comments of Edison Electric Institute at 14.

[44] Comments of Public Systems at 44.

[45] Comments of East Tennessee Group, *et al.* at 18 (emphasis in original).

[46] *Cf. El Paso Natural Gas Company*, 22 F.P.C. 260 (1959), *affirmed, El Paso Natural Gas Co. v. FPC*, 281 F.2d 567 (5th Cir. 1960).

2. Comments and Responses on Legal Grounds.

Some commenters contended that the Commission lacks the legal authority to adopt tax normalization for the items covered by this rulemaking unless the Commission first finds that no tax savings will result. Public Systems, which developed this contention, argued that Commission and judicial precedent require that any continual tax deferrals created by stable or growing plant—such as the ones the Commission recognized in this rulemaking—must be treated as a tax savings and flowed through to the consumer in rates.[47] According to Public Systems, the only exceptions to the flow-through requirement are: (a) a Congressional mandate that tax normalization be adopted, or (b) individual cases in which the Commission explicitly finds that a utility will experience a tax deferral.

The Commission rejects these arguments. We find that, under the applicable legal precedent, we have wide discretion in determining the appropriate treatment of deferred taxes. Indeed, in determining the justness and reasonableness of rates, the Commission may use a variety of ratemaking approaches. *F.P.C.* v. *Natural Gas Pipeline Company,* 315 U.S. 575, 586 (1942); *Alabama-Tennessee Natural Gas Company* v. *F.P.C.*, 359 F.2d 318, 331 (1966). The courts have indicated they will broadly defer to the Commission's decisions as long as such decisions are not arbitrary and capricious or are based on substantial evidence.[48] Several commenters agreed with this interpretation of our authority.

As discussed below, various courts, including the United States Supreme Court, have recognized the Commission's broad discretion to allow either flow-through or tax normalization. We are unaware of any court decision expressly requiring the Commission to adopt either flow-through or tax normalization on the basis of any particular factor.

In *City of Lexington v. F.P.C.*,[49] the court upheld a Commission decision approving tax normalization despite petitioner's argument that a permanent tax savings would result.[50] The Commission based its decision on several factors including its view that Congress, in bestowing a tax benefit on utilities, intended to assist in the expansion of facilities and did not intend to benefit consumers.[51] The Commission also found that "by the use of deferral accounting, the consumers are to be saved from injury."[52] In addition, the Commission declined to assume that "expansion and price inflation will continue indefinitely * * *"[53]

The court on review deferred to the Commission's expertise in the field:

> It is obvious that we are confronted in this case with a problem in a special field which requires the exercise of expert skill that has been generally entrusted by state and Federal legislation to administrative regulatory tribunals whose decisions, in the absence of abuse of discretion, should be followed by the courts. We adopt that course in this case.[54]

In *Alabama-Tennessee,*[55] a subsequent Commission (in a three-to-two vote) decided to require the use of flow-through with accelerated depreciation instead of permitting normalization as a previous Commission had done. In explaining its overruling of prior cases which had allowed tax normalization, the Commission stated that prior Commissions had erroneously concluded that the Congressionally intended benefits of liberalized depreciation could only be achieved through tax normalization. Indeed, the Commission stated that Congress left the matter to "the sound discretion of the Commission."[56]

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[47] Comments of Public Systems at 11–21.

[48] *See, e.g., Alabama-Tennessee Natural Gas, supra,* at 341; *Memphis Light, Gas and Water Division v. F.P.C.*, 500 F.2d 798 at 802; *Superior Oil Co. v. FERC,* 563 F.2d 191, 201 (5th Cir. 1977).

[49] 295 F.2d 109 (4th Cir. 1961).

[50] *Id.* at 112–113.

[51] *Id.* at 113.

[52] *Id.*

[53] *Id.*

[54] *Id.* at 114.

[55] Opinion No. 417, 31 FPC 208 (Feb. 3, 1964); Opinion No. 417–A, 31 FPC 928 (April 15, 1964).

[56] 31 FPC at 212.

Since there was no Congressional policy dictating a required ratemaking treatment of the tax benefits of accelerated depreciation, the Commission did not find that its discretion was constrained.[57] The Commission found that it could analyze the facts before it and reach a result different from that reached in earlier decisions.[58]

The Commission primarily based its decision to allow flow-through on a finding that tax normalization would produce a "tax savings" for a company's composite plant assuming the plant would remain stable or grow.[59] The Commission considered several factors in reaching its decision including probable future developments in such areas as demand for gas, plant capacity, the adequacy of gas reserves, the level of plant construction costs, and the likelihood and impact of declining plant situations.[60] The Commission also based its decision on a finding that pipelines had the financial strength to expand plant capacity without tax normalization, and that flow-through, by reducing rates, would stimulate investment more effectively than would tax normalization.[61]

On appeal, the court deferred to the Commission's ruling since it was based "on substantial evidence of present conditions and a fair guess as to future conditions in the pipeline industry."[62] The court stated that the key issue under the Natural Gas Act was not the mechanics used to arrive at a rate structure, but the reasonableness of the entire rate structure itself.[63]

The *Alabama-Tennessee* court then quoted, with approval, from the brief filed by the Solicitor General opposing Supreme Court review of the earlier 5th Circuit *El Paso* decision, *supra*, on the ground that the case presented only a matter of administrative discretion:

> * * * [W]hatever merit there may be in either method, the least that can be said is that a regulatory Commission's choice between the two (normalization or flow-through) is assuredly within its discretion, depending on the particular agency. *No general issue of law is involved*, only a discretionary choice among competing accounting systems. Such a choice is not one which warrants review by this Court. *Under the same principle, the choice is one which can be changed by the Commission should it befome convinced that the other method is preferable.*[64]

The *Alabama-Tennessee* court found that the Commission's adoption of flow-through did not limit the Commission's discretion in the future on that issue:

> The Commission must, of course, concern itself with the possibility of having misread the future and with the future's taking a turn without benefit of advice from the Commission. All things change. But we should expect agency policy to be sufficiently flexible to attempt to change with changing times.[65]

In *Texas Gas Transmission Corporation*,[66] a later Commission voted to permit tax normalization of the tax effects of accelerated depreciation for pre-1970 property and post-1969 replacement property, again reversing the position of a prior Commission. The Commission noted that while the courts had upheld prior Commission decisions approving flow-through, the courts had never indicated that such a policy was required.[67]

The Commission recognized that different considerations were present in *Texas Gas* than in the prior flow-through cases. In *Texas Gas*, the Commission primarily based its tax normalization decision on the ground that "there is little chance with respect to this plant that there will be any permanent tax savings."[68] The Commission also considered several other reasons for approving tax normalization including:

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[57] *Id.* at 210–215.

[58] *Id.* at 216.

[59] *Id.* at 215–16.

[60] *Id.* at 216–17.

[61] *Id.* at 218–19.

[62] *Alabama-Tennessee Natural Gas Company v. F.P.C.*, 359 F.2d 318, 339 (5th Cir. 1966), *cert. denied*, 385 U.S. 847 (1966).

[63] *Id.* at 331.

[64] *Id.* at 335, note 34 (emphasis in original).

[65] *Id.* at 339.

[66] Opinion No. 578, 43 F.P.C. 824 (June 3, 1970); *reh. den.*, Opinion No. 578-A, 44 F.P.C. 140 (July 21, 1970).

[67] 43 F.P.C. at 829.

(1) Before-tax coverage of interest expense would be improved;

(2) The quality of the utility's securities would be enhanced;

(3) Current cash shortages would be alleviated; and

(4) More stable tax costs would result and thus more stable rates.[69]

The United States Court of Appeals for the District of Columbia Circuit reversed the Commission's opinion in *Texas Gas.*[70] The Supreme Court reversed *in toto* and remanded the decision of the D.C. Circuit.[71] The Supreme Court recognized the Commission's wide discretion in setting rates.

Upon remand, after analyzing the Commission's reasons for concluding that a normalization policy should apply,[72] the D.C. Circuit affirmed the Commission's approval of tax normalization of the tax effects of accelerated depreciation for ratemaking purposes as based on substantial evidence.[73] In reaching its decision, the court specifically noted the Supreme Court's finding in *Memphis* that tax normalization was permissible even though it might increase rates.[74]

The courts have explicitly indicated that those decisions adopting tax normalization or flow-through are policy decisions and are within the special competence of the Commission. Prior Commissions based their decisions in those cases primarily on whether tax normalization would or would not likely create a tax deferral or a "tax savings" although they also considered other factors. In these cases, the courts have always dealt with the normalization/flow-through issue in terms of the Commission's own analysis of tax savings versus tax deferral. The courts have never held that the Commission was required to disallow normalization if there were a possibility of a constant or growing balance in the accumulated deferred tax account.

3. Conclusion: Tax Savings versus Tax Deferrals.

The Commission finds that the tax normalization policy, as set out in the final rule, will not cause utilities or their investors to realize a permanent tax savings. Firms that are continuously growing may have continual tax deferrals measured by the total amount in the deferral accounts. Continual tax deferrals are not permanent tax savings since they do not confer a permanent tax benefit on utilities or their investors. When viewed in the aggregate, tax deferrals arising from timing differences can continue into the indefinite future. But the aggregate of all timing difference transactions is simply the sum of the individual timing difference transactions and the individual transactions reverse as do their associated tax effects.

Permanent tax savings can arise from permanent differences as contrasted to timing differences. Permanent differences (in ratemaking) are differences between the amounts of expenses or revenues recognized in one period for income tax purposes and for ratemaking which do not reverse or turn around in one or more other periods. The final rule is not applicable to permanent difference transactions. It requires tax normalization only for timing difference transactions.

To the extent that prior Commissions found that permanent tax savings arose from permanent difference transactions and denied tax normalization on that basis, we agree with and confirm that finding. However, prior Commissions appear to have used the term "permanent tax savings" to apply to "continual tax deferrals". Leaving aside this semantic distinction, the

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[68] *Id.*

[69] *Id.* at 829–30.

[70] *Memphis Light, Gas and Water Division v. F.P.C.*, 462 F.2d 853 (D.C. Cir. 1972).

[71] *F.P.C. v. Memphis Light, Gas and Water Division*, 411 U.S. 458 (1973).

[72] *Memphis Light, Gas and Water Division v. F.P.C.*, 500 F.2d at 798, 801–806 (1979).

[73] *Id.* 802, 807.

[74] *Id.* at 807.

Commission does not believe a finding of evanescent versus continual tax deferrals should be the determinative factor in a decision to adopt a policy of tax normalization or flow-through.

F. Deferred Taxes as Customer-Contributed Capital; the "Loan" Analogy

To illustrate certain aspects of the difference between tax normalization and flow-through in revenue requirements over time, the Notice and the attached Staff Study used an analogy of a customer loan. It is apparent from the comments, however, that this "analogy" increased rather than reduced confusion. Indeed, the source of many of the criticisms of tax normalization can be traced to the erroneous premise that a loan is being made by ratepayers to the utilities.[75] To the extent that the Notice conveyed or supported this notion as fact rather than as an illustrative analogy, the Commission now finds it in error.

The example given in the Notice was misleading, at the least, when it hypothesized that customers make a loan to their utility equal to the tax normalization/flow-through revenue requirement difference. As pointed out by one reply commenter, utilities do not receive this amount. They only receive an amount equal to the deferred tax component of the cost of service. The rest goes to the U.S. Treasury in the form of current taxes.

Second, the example assumed a Type I timing difference. If a Type II of III timing difference had been used, the loan would have appeared to be from the utility to customers.

The analysis also assumed flow-through as the base and evaluated the incremental effects of tax normalization on required revenues as the "loan". If tax normalization had been assumed as the base for the analysis of the Type I timing difference, the loan would have again appeared to be from the utility to customers. Thus, the frame of reference and type of timing difference used in the analysis determined the source and beneficiary of the "loan".

The "loan" analogy is clearly wrong to the extent that it implies that ratepayers have an ownership claim or equitable entitlement to the "loaned monies". Tax normalization does not impose any burden upon ratepayers to pay in excess of the costs associated with the services they receive. Under tax normalization, ratepayers are charged the same rates as they would have been charged had there been no timing differences, *i.e.,* if the IRS allocated expense and revenue transactions to the same time periods as the regulatory agency.

At the most, the "loan" analogy can be viewed as illustrative. It shows that the "return" obtained by ratepayers on the "loan" is equal to the utility's after-tax cost of capital. The important point here, however, is that customers receive in lower rates the full amount of the savings achieved by companies by virtue of their having use of the deferred tax funds. The deferred taxes represent a cost-free form of financial capital to the utilities. The deduction of accumulated deferred taxes from rate base is not intended to provide customers with a return on funds loaned to utilities. Rather, as a number of parties have correctly pointed out, it is simply a way of reflecting the fact that a certain portion of rate base is not financed by investor funds so that there is no "interest" cost to the utility on a portion of its rate base. There is no "interest" cost that requires collection in rates.

The staff study proceeded from here to discuss the implications of the notion that the "return" ratepayers receive is in the form of lower rates and is thus tax-free. This analysis seems to elevate the importance of the fictitious "return" to an unwarranted level. It raises questions about the adequacy of the "return" when, from a policy perspective, this is irrelevant. Utilities employing tax normalization do not increase their earned rates of return above those they are allowed because of normalizing taxes. All the benefits achieved from having the use of deferred taxes are passed to consumers. In order to give ratepayers any higher "return" on the "deferred tax loan", the Commission would have to raise utility rates, not lower them.

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[75] This is not to say that customers do not pay rates that recover deferred taxes. They do. But paying deferred taxes in rates does not convey an ownership or a creditor's right.

The evaluation of the flow-through and tax normalization options from the point of view of whether ratepayer discount rates are below, equal to, or above the utility's after-tax cost of capital presupposes that the two policies are equally attractive from a just and reasonable ratemaking perspective. They are not equal. There are clear-cut differences between the rates set under a tax normalization policy and those set under a flow-through policy. The Commission's evaluation of these differences is that tax normalization achieves rates that are more cost-related and equitable to ratepayers over time.

Since the Commission finds the analysis of tax normalization from the perspective of a customer loan to have little merit, it also finds little merit in the criticisms of the tax normalization policy that are based on the presumption a customer loan.[76]

G. Rulemaking Versus Case-by-Case Treatment of Tax Normalization

1. Authority for Rulemaking. Several commenters argued that to the extent the Commission can adopt tax normalization it must do so through individual rate proceedings. In such proceedings, according to one commenter, the Commission can approve tax normalization only if the utility demonstrated that a tax deferral rather than a permanent tax savings is involved. Another commenter stated that a generic tax normalization rule is a *per se* violation of the just and reasonable rate standard because it permits recognition of tax expenses beyond those "actually paid" without the scrutiny of individual case consideration. As discussed above, the Commission finds that neither the "permanent tax savings" test nor the "actual taxes paid" principle is determinative of the Commission's authority to grant tax normalization. (*See* Sections II–D and II–E.)

As for the argument that the Commission must resolve the tax normalization/flow-through policy issue by adjudication rather than rulemaking, the law is directly to the contrary. Courts have frequently upheld the Commission's discretion to set rates through rulemaking.[77] This has been specifically recognized in *Alabama-Tennessee.*[78] The court held that in deciding whether to adopt flow-through or tax normalization the Commission may proceed by rulemaking or adjudication. The Commission severed the tax normalization issue from a rate case involving Alabama-Tennessee Natural Gas Company and severed the same issue from numerous other rate cases involving natural gas companies.[79]

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[76] Examples of this type of criticism include the arguments suggesting that tax normalization discourages self-generation projects or is inequitable to customers who switch dealers because departing customers lose part of the "loan" they have made. *See* Section II–B, above.

[77] *See, e.g., Permian Basin Area Rate Cases,* 390 U.S. 347 (1968) (approving the Commission's authority to set area-wide producer rates through rulemaking). The *Permian* court established that the Commission's determinations in the area of natural gas ratemaking will withstand judicial scrutiny if (1) the Commission has acted within the scope of its authority, (2) its rate order is based upon substantial evidence and (3) the "end result" is just and reasonable. 390 U.S. at 791. There is presently a conflict between the United States Circuit Courts of Appeal over the specific question of whether the "substantial evidence" test or the "arbitrary and capricious" standard applies to judicial review of rulemakings under the Natural Gas Act. However, several courts have indicated that the "arbitrary and capricious" test and the "substantial evidence" test may not, in practical effect, impose a different standard of review for informal rulemakings. *See ECEE* v. *FERC,* 611 F. 2d 554 (5th Cir. 1980), at 3019–20, n. 22; *American Public Gas Association* v. *FPC,* 567 F. 2d 1016, 1028–29 (D.C. Cir. 1977); *Associated Industries of N.Y. State, Inc.* v. *U.S. Department of Labor,* 487 F. 2d 342, 349–50 (2d Cir. 1973); *National Small Shipment Traffic Conferences Inc.* v. *CAB,* 618 F. 2d 819 (D.C. Cir. 1980). In any event, the Commission believes that this rule satisfies either test.

[78] *Alabama-Tennessee Natural Gas Co.* v. *FPC,* 359 F. 2d 318 (5th Cir. 1966).

[79] *Alabama-Tennessee Natural Gas Company,* 31 FPC 208 (February 3, 1964), *reh. den.* 31 FPC 928 (April 15, 1964).

its opinion to determine the just and reasonable rate for Alabama-Tennessee and to apply the general principle as to all other parties.[90]

On review, the court recognized the Commission's wide discretion in choosing the appropriate procedure, including rulemaking, to decide the tax normalization issue:

> The Commission was not obligated to decide the rapid depreciation issue in a rulemaking rather than a ratemaking proceeding. The choice between proceeding by general rule or by individual, ad hoc litigation is one that lies in the informed discretion of the administrative agency.[91]

The court further stated that:

> * * * As long, however, as the Commission stays within constitutional and statutory limits, it is competent to determine whether to deal with a policy problem in an adjudicatory proceeding, a rulemaking proceeding, or a special proceeding of the type employed in this case.[92]

The court concluded that:

> * * * the Commission was within its power in adopting flow-through for Alabama-Tennessee in a proceeding under Section 4 of the Natural Gas Act, even though the findings and order with respect to the petitioner establish a policy that may also affect other interstate pipeline companies.[93]

The Commission notes one commenter's discussion of the cases addressing the Commission's ability to proceed by rulemaking on tax normalization as follows:

> If anything, the courts have approved the Commission's past preference to resolve the tax normalization issue in individual rate proceedings with some misgivings, and have clearly inclined toward the view that adoption of such an industry-wide policy could best be considered in a rulemaking proceeding where all potentially affected parties could participate.[94]

Moreover, the Supreme Court has made it clear that an administrative agency possesses the flexibility to employ any procedure that it believes is best suited to effective resolution of the issue.[95]

In addition to the above-cited judicial authority for the Commission's authority to proceed by rulemaking, section 403(c) of the Department of Energy Organization Act (DOE Act) specifically provides for ratemaking by rulemaking:

> Any function described in section 402 of this Act which relates to the establishment of rates and charges under the Federal Power Act or the Natural Gas Act, may be conducted by rulemaking procedures.

The functions described in section 402, referred to above, include "the establishment, review and enforcement of rates and charges for the transmission and sale of electric energy * * * under Part II of the Federal Power Act * * *" (section 402(a)(1)(B)) and "the establishment review, and enforcement of rates and charges for the transportation and sale of natural gas by a producer or gatherer or by a natural gas pipeline or natural gas company under sections 1, 4, 5, and 6 of the Natural Gas Act * * *" (section 402(a)(1)(C)).

Tax normalization clearly relates to establishment of rates and charges under the FPA and the NGA. Therefore, under section 403(c) of the DOE Act, the Commission may adopt a tax normalization policy by rulemaking.

2. Price Squeeze. In the Notice, the Commission stated that if differing state

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[90] *Id.* at 929.

[91] 350 F. 2d at 343 (citation and footnote omitted).

[92] *Id.* (citation omitted).

[93] *Id.* at 344.

[94] Reply Comments of El Paso Natural Gas Company at 7–8. The footnote to the above quoted language provided:

"*See City of Chicago* v. *FPC*, 385 F. 2d 629, 643 (D.C. Cir. 1967) (FPC free to utilize adjudication of pipeline rates 'notwithstanding the efforts of courts and scholars to encourage greater use of regulations for broad policy declaration'); *Alabama-Tennessee Natural Gas Co.* v. *FPC*, *supra*, note 11, at 341 ('singularly eccentric that a matter as important to the natural gas industry as the Commission's about-face on liberalized depreciation' is resolved in a single pipeline rate proceeding but approves choice of procedure). *See also San Antonio* v. *United States*, — F. 2d —, No. 78-2051 (D.C. Cir. June 8, 1980) (*Slip Op.* at 33) (application of rule specifying tax normalization to individual rate proceeding upheld)."

[95] *See Vermont Yankee Nuclear Power Corporation* v. *Natural Resources Defense Council*, 435 U.S. 519 (1978).

commission/federal commission treatment of tax normalization, in whole or in part, were found to cause undue discrimination between wholesale and retail rates, then the Commission might consider the denial of tax normalization as one of the possible remedies to the undue discrimination. The Commission also stated that its inquiry into price squeeze and undue discrimination on a case-by-case basis did not prohibit it from instituting tax normalization as a general rule, since many factors, not just normalization, could cause a non-cost justified disparity between wholesale and retail rates with a resulting anticompetitive effect.

One commenter, in agreeing with the Commission that the rate effect of tax normalization is but one of the factors to be considered in analyzing the price squeeze issue, requested that the Commission give the utilities the latitude to be consistent with the state commission tax treatment of timing difference transactions. While one commenter did not believe that denial of tax normalization was an appropriate means of treating price squeeze problems, another commenter believed such denial was appropriate. This latter commenter requested that the Commission limit the denial of tax normalization, as a remedy for undue discrimination, to those items that the state commission allowed to be flowed through so that the Commission would not force a utility to flow through items that state commissions normalized. Finally, one commenter urged flexibility on the Commission's part and suggested that denial of tax normalization could be used to remedy undue discrimination between wholesale and retail rates even if the state commission allowed tax normalization.

The Commission reiterates its position as stated in the Notice that we are not prevented from instituting tax normalization as a general rule although the use of tax normalization may be a contributing factor to undue discrimination in a particular case. Many factors can contribute to a Commission finding of price squeeze and undue discrimination, including differences between federal and state commission policies, and these factors will be explored by the Commission in each case in which the price squeeze issue is raised. The Commission does intend to retain the flexibility to deny tax normalization or modify other cost of service methods as possible remedies after a finding of undue discrimination. Moreover, the Commission, in departure from the Notice, will not declare at this time that it will limit the denial of tax normalization to those circumstances in which the state commission allows flow-through and this conflict between state and federal policies is a contributing factor to the undue discrimination. Except for this change, we fully support the discussion contained in the Notice [66] on the question of the impact of the price squeeze issue on this rulemaking.

H. Tax Normalization and the Just and Reasonable Standard of the Federal Power Act and the Natural Gas Act

Several commenters argued that the tax normalization rule violates the just and reasonable rate standards of the FPA and NGA on the ground that it adversely affects consumers. Public Systems in its comments claimed that the Commission failed to address the finding in *Public Systems* v. *FERC* [67] that any policy favoring normalization "must comport with the spirit of federal utility regulation that consumers at least will suffer no detriment under CITA [comprehensive interperiod tax allocation]". [68] Public Systems claims that the *Public Systems* case prohibits normalization to the extent that such a policy acts to the detriment of consumers by preserving the benefits of continual tax deferrals (tax savings) to utilities. As discussed in Section II–E, above, the Commission finds that it can adopt a normalization policy based upon a variety of factors and is not constrained under the "permanent tax savings" (continual tax deferral) theory.

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[66] Notice at 45–48, 45 FR at 22061–2.

[67] 606 F.2d 973 (D.C. Cir. 1979).

[68] *Id.* at 979 (footnote omitted).

The Commission also finds that its tax normalization policy meets the applicable legal tests under the just and reasonable rate standard, including the consumer protection test. As Public Systems' comments correctly observed, the *Public Systems* court based the "no detriment" to consumers language upon the traditional consumer protection test under long-standing judicial interpretations of the NGA and the FPA.[89] However, the court also recognized that tax normalization must at the same time meet the traditional financial integrity test under judicial interpretations of the NGA and FPA.[90] The Commission's decision to adopt tax normalization in this rulemaking has been guided by the same standard, which amounts to a balancing test of supplier and consumer interests.

The Supreme Court in *F.P.C.* v. *Memphis Light, Gas and Water Division,* 411 U.S. 458 (1973), reviewed the authority of the Commission to use tax normalization in the ratemaking treatment of depreciation. In upholding the Commission's authority to adopt tax normalization, the Court made clear that there were "two aspects of the power of the Commission to fix 'just and reasonable rates'".[91] One aspect was the desire to protect consumers against exploitation; the other aspect was to insure that the utility's revenues were adequate to ensure its financial integrity.[92] The Court further stated that the depreciation practices affect rates and that there was no indication that Congress in the Tax Reform Act of 1969 desired to modify "the broad discretion of the Commission delineated in *Hope Natural Gas* and in other rate cases."[93]

The Court also made clear that the just and reasonable standard could be satisfied even if it increased rates:

> We find no trace of a suggestion that the Federal Power Commission was denied authority to determine whether on particular facts the abandonment of flow-through by a utility within the parameter of the Tax Reform Act of 1969 would be in the public interest as envisaged by the Natural Gas Act, even thought it might increase rates.[94]

The Court, in reversing the decision of the D.C. Circuit that had vacated the FPC's approval of tax normalization for accelerated depreciation, emphasized the meaning of the just and reasonable standard:

> As already noted, under *Hope Natural Gas* rates are "just and reasonable" only if consumer interests are protected and if the financial health of the pipeline in our economic system remains strong.[95]

On remand,[96] the D.C. Circuit reviewed the Commission's use of normalization on the basis of whether that use comported with the Supreme Court's articulation of the just and reasonable standard.[97] In holding that it did, the court noted the Supreme Court's language sanctioning tax normalization even though it might increase rates and recognized that consumers would be protected under normalization even if rates increased:

> For while Texas Gas is not currently paying taxes at straight-line rates, it is incurring the liability to pay increased taxes in the future. Such a method as normalization, whereby current consumers are prevented from forcing future consumers to pay their deferred taxes, does not amount to causing an increase of rates based on fictitious taxes.[98]

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[89] 606 F.2d 979. The footnote to the "no detriment" language provides in pertinent part:

> Both the Natural Gas Act and the Federal Power Act aim to protect consumers from exorbitant prices and unfair business practices. This purpose can be seen in the statutory requirement that rates be just, reasonable, and nondiscriminatory, 16 U.S.C. 824d(a), (b) (1976); 15 U.S.C. 717c(a), (b) (1976). *See FPC* v. *Hope Natural Gas Co., supra,* 320 U.S. at 611–12 (other citations omitted.).

[90] The case footnote cited in footnote [89] above further provides:

> Of course, protection of the consumer includes maintaining the financial integrity of the regulated firm * * *

[91] 411 U.S. at 465–6.

[92] *Id.* at 465–6; 474.

[93] *Id.* at 466.

[94] *Id.* at 472–3.

[95] *Id.* at 1474.

[96] *Memphis Light, Gas and Water Division v. FPC,* 500 F.2d 798 (1974).

[97] *Id.* at 807.

[98] *Id.* at 807 (footnote omitted).

The key point is that the court left to the Commission's discretion the ability to approve tax normalization on the basis that rates will be just and reasonable over the *long term*, even though rates might increase over the *short term*.

The Commission, in adopting the tax normalization policy in the instant rulemaking, has considered both the industry and consumer aspects of the just and reasonable rate standard.[99] Moreover, the Commission has demonstrated that tax normalization will protect all consumers against exploitation by providing equitable treatment for both present and future ratepayers. In the long run, consumers will suffer no detriment under normalization because they will receive the full tax benefit of expenses they have paid.

I. Comments on the Impact Analyses

In the Notice, the Commission included a staff analysis of the impacts that the proposed tax normalization rule would have on four items:

1. Rates
2. Cash flow
3. Rate of return
4. Cost of capital

This section discusses the comments received on the rule's impacts in these areas and concludes that the initial impact estimates were reasonable and can be relied upon to guide the Commission's decision on whether a general rule to apply tax normalization should be adopted.

1. Rate Impact

a. Staff impact analysis

Few substantive comments were submitted criticizing the overall reasonableness of staff's estimates of the impact of the proposed policy on electric utility and natural gas pipeline rates. Some commenters noted that staff's impact analysis showed that consumers would pay higher rates for the foreseeable future under tax normalization. One commenter claimed that tax normalization has a "substantial adverse effect on rates."

The Commission has reviewed staff's study and is aware that under certain circumstances the rates under tax normalization will be higher than under flow-through for some period of time. The Commission does not believe that the rate effects can be accurately characterized as "substantial". Since tax normalization more equitably allocates tax costs over time and is thus the more rational policy, it seems more reasonable to view the rate impact as showing the extent to which flow-through, for most timing differences, forces future customers to subsidize current customers. Thus, the lower the flow-through rates are in comparison to normalization rates, the greater the potential inequity to customers over time.

Further, the Commission believes that those commenters who view tax normalization as imposing higher rates are overlooking or underestimating the potential impact of tax normalization on the cost of capital. They also seem to overlook the fact that tax normalization applied to timing differences like plant removal costs tends to produce lower rates initially than flow-through. Tax normalization of plant removal costs (expecially nuclear decommissioning expenses) is likely to begin having significant and widespread impacts on wholesale rates over the next few years.

A few commenters suggested that the Commission should place more emphasis on the high ends of the ranges in staff's projected industry growth rates. None, however, provided any real basis for a finding that there was any downward bias in staff's projected impacts.[100]

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[99] These considerations are summarized in Section I-B above.

One commenter criticized the staff study for relying on a model based upon industry-wide averages that could not accurately reflect the rate impact on individual companies. The assumed capitalized expense ratio for natural gas pipelines was cited as an example of how the impact estimates could be in error. It was alleged that the projected 1979 through 1994 capitalized expense ratio for El Paso Natural Gas Company is 76.1 percent—well above staff's 4 percent assumed ratio for natural gas pipelines. However, this high ratio is due primarily to intangible drilling costs and the ratio based only on construction-related taxes, pensions and interest—the only items quantified by staff—is 4.9 percent. Thus, El Paso's capitalized expense ratio for those items considered is not that different from staff's assumed ratio.

The timing differences arising from intangible drilling costs affect only a few natural gas pipelines. These are pipelines that have natural gas production operations that continue to receive cost of service treatment. In view of the isolated instances in which this timing difference would apply, it was reasonable for the staff's analysis to ignore intangible drilling costs.

In evaluating the rate impacts of the proposed policy, the Commission finds staff's approach in estimating the average industry-wide impacts a reasonable one. The impracticality of doing individual company forecasts together with the fact that the rate impact is only one of a number of factors in the Commission's evaluation of the proposed policy makes the industry-wide approach desirable.

A few of the commenters criticized staff's analysis for assuming income tax rates will remain constant. The implication in their comments was that the utilities and their stockholders will profit from tax rate reductions. As explained below (Section II–J.6), no such result is likely to occur under the Commission's ratemaking and accounting policies. In terms of the impact analysis, projecting reductions in tax rates would result in reductions in rates under both normalization and flow-through policies, leaving the revenue requirement differentials relatively unaffected. Thus, little purpose would have been served in assuming that tax rates will fall in the future.

Finally, one commenter criticized the Commission for not providing support for the claim that "staff's quantitative evaluation covers the types of timing differences at issue that, for the majority of individual utilities, can be expected to have the largest impact on rates." The commenter further criticized the Commission for not providing any quantitative data on the aggregate impact of the items excluded from the staff study.

The Commission relies on the expertise and experience it gains through participation in rate cases and in conducting company audits for evaluating the comprehensiveness of its impact analysis. Furthermore, the Commission explicitly asked commenters to provide data on additional timing difference transactions that may have been excluded from staff's analysis. Only one substantial comment was received on this issue—that related to intangible drilling costs—which we addressed above.

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[100] One initial comment (Public Systems at p. 47), cited a recent Edison Electric Institute (EEI) study entitled "Economic Growth in the Future—II" to suggest that staff's projected 2–4 percent range of real growth rates in electric utility "capacity" was too low. That study projected a "Preferred Scenario" growth rate in electricity "generation" of 4.3 percent between 1978 and 2000. Public Systems' citation is misleading. First, the study looks at various scenarios for the future and projects what growth rates may occur under a variety of assumptions. The "Preferred Scenario" is only one of five scenarios examined. Second, the growth rate cited by Public Systems is for electricity generation, not capacity, which is the basis for staff's real growth rates. The EEI "Preferred Scenario" growth rate in "capacity" is 3.8 percent, within the 2–4 percent range considered reasonable in staff's analysis. Growth in capacity was used in the staff study because the study was measuring the effects of the alternative policies on capacity-related timing differences.

Appendix C of the Notice which listed additional timing differences covered by the proposed rule was based on an informal review by staff of electric utility and natural gas pipeline Annual Reports. These Annual Reports are publicly available, and so the thoroughness of staff's analysis could have been evaluated. No commenter has shown any significant deficiency in staff's rate impact analysis.

b. Other impact analyses. Public Systems presented a 30-year simulation analysis of the impact on the electric utility industry of normalizing certain timing differences (accelerated depreciation and capitalized interest) and investment tax credits. The principal conclusion was that normalizing these items "will produce phantom taxes of at least $800 billion and a stockholder windfall of $1.2 trillion on new plant additions over the next thirty years."[101]

The deficiencies of Public Systems' study are numerous. First, the Commission notes that the study is largely irrelevant in that it deals with investment tax credits and accelerated depreciation. Public Systems stated that only about one-third of the estimated impact (that due to normalizing capitalized interest) can be attributed to the proposed rule. Second, even this is an overstatement. As two reply commenters remarked, the study overstated capitalized interest by assuming that there are no equity portions in AFUDC. According to one reply commenter, capitalized interest accounted for only 40 percent of AFUDC in 1978. Third, the study uses interest expenses as a tax deduction twice: Once during the construction period and again during the operating life by computing tax depreciation on total plant.

A fourth deficiency was that the Public Systems study never explained the basis for alleging that "phantom taxes" are windfall gains to stockholders. The Commission notes that the study also does not provide any explanation of how stockholders actually receive returns in excess of those allowed. The study simply defined the actual return to stockholders as composed of the "allowed return plus phantom taxes and that portion of the depreciation expense allowance that is attributable to plant additions that were purchased with customer-contributed capital (i.e., plant which was financed by the deferred tax and JDIC [sic] reserves)."[102] As explained in various other sections of this order,[103] the Commission finds no basis for concluding that stockholders benefit in any direct monetary way from the proposed policy.

One other comment contained a forecast, through 2014, of the rate impact of tax normalization compared to flow-through for a particular company. This analysis, presented by East Tennessee Group, *et al.*, showed that for El Paso Natural Gas Company, rates calculated under tax normalization would fall and remain below rates calculated under flow-through after 1986. This analysis is wholly consistent with staff's impact analysis which showed that, for natural gas pipelines, normalization rates would, over the next decade or so, fall below flow-through rates.[104]

2. Cash Flow Impact. In the Notice, the Commission pointed out that "normalization tends to improve a utility's internal cash flow when the need is greatest and to decrease it when the need is less" (45 FR at 22059). More specifically, with a 50 percent composite federal/state tax rate, "normalization provides additional cash in the amount of 50 percent of any incremental cash need arising from timing difference transactions and, similarly, reduces any incremental cash 'excess' by 50 percent"

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[101] Comments of Public Systems, Exhibit B at 9.

[102] Comments of Public Systems, Exhibit B at 8.

[103] See especially Section II–I.4 below.

[104] See Comments of East Tennessee Group, *et al.*, App. B, MJM–3 at Schedules 1 and 2. The East Tennessee Group, *et al.*, uses its rate impact analysis to show how ratepayers are, in some way, harmed by not being given an adequate "return" on their "loan". For reasons discussed in Section II–F, we reject the latter analysis since it assumes that tax normalization involves capital contributions from ratepayers.

(45 FR at 22077). This conclusion is based upon the analysis, provided in the staff study attached to the Notice, of the matching in rates of timing difference transactions with their associated tax effects under tax normalization.

One commenter found this reasoning to be circular, arguing that it was grossly unfair of the Commission to support higher rates solely on the ground that rates are thereby higher, and was a "pernicious" justification for tax normalization. The commenter further hypothesized a situation it believed was a logical outgrowth of an illogical premise: if cash flow were really going to decrease in the future, as suggested in the Notice, at a time when a utility's rate base is substantially lessened by high deferred tax accounts and when expenditures for construction were growing, then the potential impact on a utility's ability to meet its cash obligations—including dividends—could be devastating and could be used to justify future rate increases based on adverse cash flow *despite* adequate earnings.

We agree with a reply commenter who countered this argument by explaining that the central point is that cash flow under tax normalization coincides better with cash needs than under flow-through, since tax normalization matches the cash flow benefits with the associated cost. The reply commenter faulted the initial commenter for basing its hypothesized situation upon two incorrect assumptions: that a utility's capital investment will grow and that it will grow steadily. Only steady growth can mask the adverse cash flow consequences arising from the rate recognition of costs at a different time from the rate recognition of associated tax benefits under flow-through. Furthermore, the reply commenter recognized that, while the level of investment in some utilities may grow at a moderate or rapid rate, it is reasonable to expect that other utilities' investments will not grow and may decline, based on current trends in prices and usage rates for energy.

Another reply commenter substantiated the view that growth in the electric utility industry is not likely to be steady. According to this reply commenter, economies of scale dictate that even a utility experiencing rapid growth will build one or two large plants instead of six or seven smaller ones. Further, new plant costs are never spread evenly over the construction period, but rather tend to bunch in certain years. An example was given of a five-year construction period in which 10 percent of the costs were expended in each of the first, second and fifth years but 35 percent of the costs were expended in each of the third and fourth years.

Several commenters faulted the Commission for relying on normalization as a means to improve the current cash flow position of utilities. They argued that there are other, more equitable ways by which cash flow can be improved, such as through the use of contributions in aid of construction. They further argued that current growth forecasts, particularly when viewed with current tax laws, eliminate the across-the-board need for increased cash flow: that utility capacity and supply positions today are considerably improved over what they were six years ago; and that many utilities have cut back their construction budgets not because of an inability to finance but because they had overbuilt.

These comments are misplaced. The Commission did not propose the instant tax normalization rule for the purpose of improving the cash flow or financial position of utilities. Instead, the Commission, in the Notice, merely attempted to show the impact of tax normalization on utilities' cash flow positions.

This is not to say that the impact on cash flow is not an important policy consideration in the Commission's evaluation of the tax normalization and flow-through policies. It is. Timing differences are a source of cash flow difficulties for utilities. This is because the most significant timing differences are created by ratemaking deferrals of utility costs. For example, utilities are required to make cash outlays for construction-related interest, taxes, and pension costs prior to their recovery of those costs in rates charged customers. This has been an important factor in the cash flow problems faced by electric utilities over the last decade. Tax normalization, by permitting utilities to retain the tax effects (benefits) of those expenses when the cash outlays have to be made, provides utilities with some cash (deferred taxes) to meet these financing needs.

The starting point in the Commission's cash flow analysis is the assumption that, in large part, the recognition of expenses for tax purposes is more closely coincident in time with the actual utility outlays of funds for those expenses than is their recognition for ratemaking. This is true for construction-related interest, taxes, and pension costs, regulatory commission expenses, and plant removal costs—the major items subject to the instant rule. With a 50 percent tax rate, tax normalization reduces the net cash outlays by a utility for these expenses by 50 percent. Conversely, when these expenses are recognized in ratemaking and the utility has no cash outlay requirement for them, tax normalization reduces the utility's cash inflow by 50 percent of the amount recognized in rates. Further, as with the other impacts, these conclusions hold whether one is looking at a single transaction or many transactions.

These results are significant in their showing that tax normalization acts as a stabilizing force on utility cash flows. The Commission finds this an attractive feature of the tax normalization policy, but it is not the reason the Commission is adopting such a policy. The Commission has not been swayed from the logic and value of this result by the comments.

3. Rate of Return Impact. None of the commenters gave substantive reasons for opposing the finding of the Commission contained in the Notice that deferred taxes do not accrue to the benefit of utility stockholders. No party raised any objections to the portion of the staff study, attached to the Notice, discussing this impact. At most, the comments of the opponents to tax normalization simply asserted that utility stockholders benefited from the proposed policy.

One commenter claimed to estimate that tax normalization of liberalized depreciation, Asset Depreciation Range life differences and AFUDC interest along with the investment tax credit would result in windfall earnings of about $1.2 trillion dollars during the next 30 years.[105] As explained above (Section II–I.1.b), the analysis of this commenter is fatally flawed. With respect to the commenter's assertions of windfall earnings, it bears reiterating that deferred taxes cannot be paid out as dividends or placed in retained earnings under the Commission's tax normalization accounting rules. Tax normalization does not inherently give utilities (or their stockholders) an opportunity to earn returns in excess of those nominally allowed.

The idea of a shareholders' windfall under tax normalization was also debunked by one reply commenter on the basis that the stock market has not reflected any such supposed windfall. It was pointed out that if tax normalization effectively doubles or triples the return to stockholders, then that should be reflected in a doubling or tripling of stock prices of utilities using tax normalization policies. Since this has not been observed and, in fact, one finds utility stocks selling below book value, it cannot be claimed that stockholders are receiving or anticipating a windfall.

Another reply commenter used an analogy with "accounts payable" to show how no windfall results from tax normalization even when the firm is growing. While a growing firm will have a growing amount of accounts payable, that fact does not have any implication for the firm's profitability. The firm cannot use funds from its accounts payable to pay dividends or increase retained earnings. Even though the total of accounts payable may grow, the firm is not "permanently" deferring payments to its creditors: it is not receiving a permanent subsidy from its creditors since each individual account is paid when it is due. Similarly, while the total of accumulated deferred taxes may grow, that "continual" deferral does not imply a permanent subsidy since, over the life of each timing difference transaction, the effects of the associated deferred tax debits and credits net out to zero. Certainly, no subsidy accrues to the benefit of utility shareholders under tax normalization.

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[105] Comments of Public Systems, Exhibit B at 8.

The Commission reaffirms its earlier statement that deferred taxes arising under tax normalization do not benefit utility stockholders. Earned rates of return are unaffected by the existence of deferred taxes; thus, the rate of return impact between tax normalization and flow-through is neutral. To the extent that capital costs are lower under tax normalization than under flow-through, allowed rates of return would be adjusted to reflect these lower capital costs. Finally, deferred taxes do not accure to stockholders any more than the associated deferred costs accrue to ratepayers, given the Commission's ratemaking and accounting policies.

4. Cost of Capital Impact. The Commission in the Notice concluded that the weight of the evidence supported the view that the cost of capital to utilities tended to be lower when they used tax normalization rather than flow-through. This evidence, presented in the staff study attached to the Notice, included economic logic, recent available data and a number of statistical studies completed between 1965 and 1979.

The comments contained no criticisms of staff's list of four theoretical arguments used to support the existence of a lower cost of capital under normalization. However, four other arguments that were presented in the comments attempted to support the opposing view; that is, the use of flow-through resulted in a lower cost of capital than the use of tax normalization. The Commission finds none of these arguments persuasive.

First, it was contended that the accumulated deferred taxes arising from tax normalization constitute a senior liability to utilities. These taxes were alleged to increase a utility's leverage and thus the financial risks faced by investors (presumably both lenders and stockholders).

There are a number of problems with this argument. Assuming no change in business risk and assuming investors place some constraints upon a utility's use of leverage, one would expect the higher financial risk due to accumulated deferred taxes to be offset by a reduction in the use of conventional types of senior liability. The evidence, however, does not support this. The staff study showed that, if anything, utilities that normalize tended to have a higher debt ratio than flow-through utilities. The debt ratio of utilities that normalized average 54.2 percent for the period 1974 through 1978. The comparable statistic for flow-through utilities was 53.4 percent. These rates were based upon capital structures that excluded deferred taxes. If accumulated deferred taxes were seen as a senior liability, the debt ratios of utilities that normalize (calculated to include the deferred taxes) would be higher still. Thus, the empirical evidence appears to contradict the notion that investors place a higher risk on utilities that normalize.

Another problem with this theory is the fact that whether utilities use tax normalization or flow-through they face the same future tax liabilities. The difference is that utilities that normalize accumulate funds to pay that liability (the accumulated deferred taxes) while flow-through utilities must await allowances in future rates to pay those taxes. It seems more logical to expect investors to view utilities that collect now in rates for taxes they will have to pay in the future as less risky than those utilities that have to wait until the taxes are actually due to be paid before collecting them in rates. Thus, the existence of accumulated deferred taxes should more reasonably be viewed as reducing risk and capital costs, not increasing risk and raising costs.

Finally, when the contention that investors view accumulated deferred taxes as a senior liability is set in the context of a growing utility, it is inconsistent with another, often-made argument favoring a flow-through over a tax normalization policy. One cannot with consistency argue that the deferred taxes arising under tax normalization are "permanent tax savings" never to be paid to the Treasury and at the same time argue that deferred taxes are viewed by investors as a senior debt obligation that makes the return of their investment funds more risky. In order for deferred taxes to be viewed as a liability, there must be some significant probability that they will, in fact, have to be paid. Thus, flow-through proponents who argue that these taxes are permanently saved, not deferred, cannot logically also contend that investors view the taxes as a liability that increases the risks they face.

A second argument put forth by the commenters that flow-through produces lower capital costs is also related to accumulated deferred taxes. It was argued that the deduction of accumulated deferred taxes from rate base subjects the earnings available to investors to increasingly greater volatility as the level of accumulated deferred taxes increases. This volatility is alleged to translate into greater risk and higher capital costs under tax normalization.

This argument also is unpersuasive. The deduction of accumulated deferred taxes from rate base reflects the lower cash return requirements a utility has under tax normalization. The deferred tax funds reduce a utility's need for outside debt and equity funds in financing investment which, in turn, reduces its cash outlays for interest and dividend payments. Thus, any volatility in earnings arising from accumulated deferred taxes would seem to logically track the underlying need for earnings. Said differently, normalization stabilizes earnings rather than creates volatility in earnings to investors.

Instability in earnings to investors under normalization is the theme of a third argument that could be interpreted as supporting the lower flow-through capital cost thesis. One commenter attempted to illustrate this instability by an example showing the effects of a 10 percent reduction in sales on earnings available to common equity under the alternative policies of tax normalization and flow-through.[106] This analysis is also flawed. The commenter presented a single period analysis where that period is the initiating year of a Type I expense timing difference. No analysis was made of the turnaround periods for the timing difference. Furthermore, the values of the parameters are inconsistent.[107]

The final argument raised in the comments to support the view that the flow-through cost of capital is lower than the cost of capital under tax normalization is based on the total return dollars allowed under the alternative policies. The argument is simply that, because more return dollars are earned or allowed under the flow-through policy than under the tax normalization policy over the life of a plant, the cost of capital under flow-through tends to be lower. This argument ignores, however, that the utility has greater cash return requirements to meet under flow-through, since it does not obtain deferred tax dollars to assist its financing of deferred expenses, such as AFUDC interest. Thus, this argument is also unpersuasive.

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[106] Comments of Cities at 9–10.

[107] The commenter showed, under tax normalization, an operating income of $50 together with a tax allowance of $100. Under flow-through, an operating income of $50 was combined with a tax allowance of $50 in the example. Assuming that "operating income" means equity income, the equity income of $50 corresponds to a $50 total tax allowance under normalization, not $100. Under normalization, a timing difference has no effect on the relationship between the equity return and income tax allowances. A $50 expense recognized for tax purposes but not for ratemaking has current and deferred tax effects of ($25) and $25, respectively, which cancel each other out in their effects on the tax allowance. Under flow-through, however, the effect of a $50 expense timing difference is a reduction in the income tax allowance of $50 so that in the example there should have been no income tax allowance.

The comments contained no substantive criticisms of the empirical studies cited in the staff study as supporting the lower cost of capital for utilities using normalization. Some commenters suggested, however, that these studies, as well as the statistical comparisons made by staff, should be ignored since the results are related primarily to the use of normalization for accelerated depreciation by the instant rule.

The Commission does not agree. In the absence of any convincing evidence to the contrary, the Commission believes it a reasonable presumption that if normalization of accelerated depreciation lowers the cost of capital to utilities, then normalization of other timing differences will give like results. The referenced studies do not give reliable evidence on the magnitude of the cost of capital impact of the Final Rule, but they do provide substantive support as to the direction of such impact.

Finally, the Commission does not find the criticisms of staff's supplemental statistical comparisons persuasive. Some commenters referred to these statistical comparisons as crude and lacking statistical controls to ensure that the results are causally and not coincidentally related to the tax normalization policy. The Commission's finding with respect to the impact of tax normalization on the cost of capital does not rest solely on staff's analyses. The comparisons made by staff were intended to update and supplement the numerous studies cited in the staff study. The conclusions derived from Staff's data are in accord with those studies.

One commenter [108] performed some trend analyses on certain of staff's comparison data to show that the difference between the cost of equity capital under the two policies was decreasing over time. The analyses used staff's market-to-book and price-earnings ratio data for the years 1974 through 1978. The statistically-derived trend lines indicated that while the cost of equity capital to utilities using tax normalization was below the cost to utilities using flow-through in each of the years through 1978, the differential was decreasing so that by 1979 the cost to utilities using tax normalization would exceed the cost to flow-through utilities. The commenter presented data for 1979 to verify this statistical result.

The Commission finds these trend analyses flawed. If the use of tax normalization lowers *or raises* the cost of equity capital relative to the use of flow-through, that result should be independent of time. The commenter provided no rationale for that relationship to change over time. As a reply commenter stated in reference to these trend analyses, statistical correlations cannot establish causality; causation must be justified on theoretical grounds. Further, the Commission also agrees with the criticisms, in the reply comments, that (1) no justification was given for the nonlinear equation used in the trend analyses, and (2) the statistical results are unreasonable since they indicated that the cost of equity under normalization would continually increase relative to the cost under flow-through.

In summary, the Commission finds no evidence in the comments that contradicts or otherwise negates the conclusions reached in the staff study as to the cost of capital impact of the proposed rule. The final rule is found to have beneficial effects on the cost of capital to utilities.

J. Other Issues

This final part of the analysis of comments covers several other issues raised by various parties. These issues are:

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[108] Comments of Cities at 13–19.

1. Normalization of the Tax-on-Tax Effect
2. Rate Base Levelization
3. Contributions in Aid of Construction
4. Revenue/Rate Stability
5. Efficiency Incentives
6. Tax Rate Changes
7. Depreciation of Plant Financed by Deferred Taxes

Each of these issues and the comments on them are discussed in turn below.

1. Normalization of the Tax-on-Tax Effect. One commenter argued that application of the Commission's proposed rules will not result in a matching of all costs with all associated tax benefits. The commenter argued that the rulemaking has gone only part of the way toward achieving a true matching since it does not provide for normalization of the tax-on-tax effect. The thrust of this argument is that tax normalization increases revenue requirements, thereby increasing current income tax expense. Since the increase in current tax expense is caused by normalizing timing differences, the commenter believes that proper matching requires that the additional current income tax expense be deferred until the timing difference which created the tax expense reverses and is used to reduce revenue requirements.

Several commenters responded to the above argument by pointing out that, if such a proposal were adopted, it would completely defeat the matching principle on which tax normalization is based. Indeed, the reply commenters stated that, if the "illogical tax-on-tax argument" were carried to its illogical conclusion, the amount of normalized revenue would asymptotically approach zero. We agree with these statements.

The reply commenters additionally point out that the Commission has already dealt with the tax-on-tax issue in *Southern California Edison Company.*[109] In that case, the Initial Decision, affirmed by the Commission, found the same argument that is made by the comments in this rulemaking technically invalid. The error is that it treats as an interperiod timing difference an item that is not an expense deduction for income tax purposes, but instead is the resultant effect of such timing differences—that is, the deferred income tax itself.

The Commission finds that the proposed rule should not be modified to provide for the "normalization" of the tax-on-tax effect for the reasons stated above.

2. Rate Base Levelization. Comments were made that flow-through produces annual revenue requirements that are more level than those produced under tax normalization. According to the commenters, customers pay a high proportion of total return dollars in the early years of a plant's life and such return decreases over time as the plant is depreciated. It is alleged that, under flow-through, the tax component of a cost of service is low in the early years and increases over time as the tax benefits are used up. The effects of the combination of the high return and the low tax component in the early years and the low return and the high tax component in the later years, the argument runs, is to levelize rates over time. Comments were also made that the rationale underlying the even spreading of tax benefits that results from normalization would logically require rate base levelization.

Reply commenters argued that the major fallacy of the levelization suggestion is that it applies a principle to rate base and return that is not essential to the normalization of deferred taxes. Although the result of tax normalization is frequently to reflect tax costs and benefits in rates in equal amounts, the principal objective of normalization is not one of levelizing taxes but, instead, of matching tax benefits with cost responsibility. They also argued that the levelization proposal is really nothing more than an attack on current concepts of depreciation as a proper costing principle and that these concepts are not at issue in the proposed rulemaking.

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[109] Docket No. ER76-205, Opinion No. 62, issued August 22, 1979; Opinion No. 62-A, issued March 20, 1980.

The Commission agrees with the reply comments that our rate base and depreciation methods are not at issue in the proposed rulemaking. The rate base levelization suggestion need not be considered herein as it is outside the scope of this rulemaking. The levelization of revenue requirements is not a regulatory goal that the Commission is seeking to achieve by its tax normalization policy.

Further, it should be noted that flowing through the tax effects of the predominant types of transactions considered in this proceeding (construction-related interest, tax and pension costs) would not generate a more level structure of rates over the life of a plant. This is because flow-through would reduce rates only during the plant's construction period and increase rates over existing levels in an even fashion over the plant's life.

3. Contributions in Aid of Construction. Some commenters proposed, as an alternative to tax normalization, the use of contributions in aid of construction to provide additional cash flow if rates under flow-through do not otherwise provide adequate cash flow. They argued that contributions in aid of construction have less adverse impact on ratepayers while providing the same cash flow to utilities as would tax normalization. The gist of their argument is that contributions in aid of construction are non-taxable to the recipient; therefore, such contributions avoid the tax-on-tax increase that results from tax normalization.

In response to the contribution suggestion, reply commenters convincingly argued that contributions in aid of construction are not a viable alternative to tax normalization. They stated that contributions in aid of construction would not produce intergenerational equity among ratepayers because the construction would be paid by ratepayers during the construction period of a plant, but would benefit ratepayers in later years. Commenters further pointed out that the contributions in aid of construction proposal assumes a tax result which, in fact, may be unobtainable under current tax laws, since such contributions are not necessarily non-taxable.

The Commission agrees with the reply comments and will not adopt the suggestion concerning contributions in aid of construction.

4. Revenue/Rate Stability. Several commenters argued that the Commission, because of its reliance on the single transaction case in its rulemaking, has failed to demonstrate in any real-world situation that rates are more stable under tax normalization than under flow-through. They argued that whether tax normalization or flow-through would produce more stable rates depends on many considerations such as the number of construction projects undertaken over time, the length of construction of such projects, the magnitude of the deferrals during each year of construction, and the service life of the plants constructed.

The Commission agrees that the factors mentioned have an effect on rate stability. As pointed out in the reply comments, however, it is an uncontestable arithmetic truth that a policy that matches the rate recognition of tax benefits with the rate recognition of the costs which produced those benefits results in a "netting-out" effect that stabilizes swings in revenue requirements. Under flow-through, the benefits and costs are accounted for in different periods. We agree with the reply comments.

Utility growth, as suggested by some commenters, may ameliorate the swings in revenue needs associated with flow-through. However, the Commission believes that it would be incorrect to assume that each utility affected by this rulemaking will grow relatively rapidly and that the growth rates of the individual utilities will be steady. As pointed out in the reply comments, these are conditions that would be required in order for flow-through to produce stable rates.

5. Efficiency Incentives. A few commenters alleged that tax normalization tended to promote "overcapitalization" or the excessive and imprudent reliance on capital intensive technology. In essence, all the arguments presented to support this thesis are based on the view that the use of tax normalization results in utilities' and their stockholders' having the ability to earn "effective" rates of return in excess of their incremental cost of capital.

As one of the reply commenters explained, "no firm has an incentive to make additional investments unless it believes that the return it will earn on those additional investments is greater than the cost of capital." [110] But the Commission's practice of deducting accumulated deferred taxes from rate base does not allow utilities to earn a return on those investments financed with deferred tax funds. No excess profits accrue to the utilities and their stockholders from the use of tax normalization. This statement echoes throughout this order and the Commission finds it fully supported by the record. The Commission finds no basis in the record to conclude that tax normalization will lead to an inefficient allocation of resources.

6. Tax Rate Changes. Some commenters argued that normalization does not and cannot allocate tax effects over time because, unlike other costs that are known and measurable, the tax consequences of timing difference transactions are unknown. The tax regulations that may exist in the future may not be known at the time the timing difference originates. They contended that since tax laws change, one cannot say that the determinants of tax liability during one period will necessarily reflect the tax liability in a subsequent period—sometimes as far as 30 years in the future.

The Commission agrees that tax laws and, particularly, tax rates may change, but we also agree with the reply comments that this possibility is not a basis for failing to provide for deferred taxes. If income taxes are computed on a normalized basis for cost or service purposes, items of expense and revenue entering into the cost of service determination are also used in determining the income tax allowance portion of the cost of service. The tax effects, determined at the current tax rate, of the difference between the amounts so used and the amounts claimed in the tax return are placed in a deferred tax account to be used in later periods when the differences reverse. The balance in the deferred tax reserve is therefore a residual of past tax costs over past tax payments and may or may not be sufficient to cover future excess tax payments over future tax costs, depending on the statutory tax rates in the future. Any excess or deficiency in the deferred tax reserve does not, however, result in a windfall to either shareholders or ratepayers since the balances will systematically be subject to a reconciliation in future rates.

As stated in the reply comments, any disparity between the actual tax effect in the year the timing difference originates and in the year the timing difference reverses is a normal and inherent part of the accounting process. This variation is no more than that involved in assigning the original cost of properties used in providing customer service to the periods of use. Simply because the deferred tax accounting process may not assign the "perfect" amount to each respective period is no reason to reject the practice.

In addition, while the Commission recognizes the potential for tax regulations to change, it believes that it is more reasonable and equitable to consumers over time to base rates on the assumption of permanence in current tax regulations than to base them on the assumption that there will necessarily be changes in any future tax liability associated with current timing difference transactions. As discussed more fully in the Section-by-Section analysis of the final rule (Section III below), the Commission has made sufficient provision for ratemaking treatment of tax rate changes.

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[110] Reply Comments of Edison Electric Institute at 12.

7. Depreciation of Plant Financed by Deferred Taxes. One respondent commented that if normalization is adopted by the Commission there is a need to reduce gross plant investment by the resultant accumulated deferred income taxes so that a cost of service will not include amounts for depreciation expense on plant financed by ratepayers.

The Commission does not believe that this argument has merit. As the reply comments pointed out, the above proposal views deferred taxes as customer-contributed capital, which it is not. (*See* Section II–F above.) The benefit of accelerated tax deductions is only the time value of money which benefit is given to ratepayers through the deduction of accumulated deferred taxes from rate base. The deferred taxes are only available temporarily and are dissipated as lower tax deductions are available in later years.

III. Section-by-Section Analysis of Comments and Final Rule

The previous section explains the bases for the Commission's adoption of tax normalization as the preferred ratemaking method for handling timing differences. The Commission now turns to a discussion of the comments on the provisions in the proposed rule, the suggested modifications to the proposal and a section-by-section analysis of the final rule adopted by the Commission.

A. *Applicability*—§ 2.202(a). Section 2.202(a)(1), as proposed, stated that this section applies to treatment for ratemaking purposes of all timing differences except those specifically covered by other Commission orders and opinions. The final rule leaves the proposed § 2.202(a)(1) substantively unchanged. Proposed § 2.202(a)(2) listed the excluded timing differences that qualify for tax normalization treatment under one or more prior Commission orders or opinions.

One of the commenters in this proceeding disputed the Commission's description of the present policy regarding the Class Life Asset Depreciation Range (ADR) tax provisions. Through error, the proposed rule did not specifically state that ADR provisions creating a timing difference would be excluded under the proposal. An identification of ADR provisions as items not covered in this rulemaking was made in the preamble and a general reference was made to timing differences arising from accelerated methods of depreciation in proposed § 2.202(a)(2)(iv), relating to Order No. 504. The ADR provisions were covered under the Order No. 504.

The commenter stated that Order No. 504 was an accounting order that did not specify ratemaking treatment for ADR provisions. The commenter further stated that Commission Opinion Nos. 739 and 739–A had provided that timing differences arising from ADR life differences were to be covered by the 530 series of orders. Thus, the commenter concluded that the Commission had erred in the preamble of the proposed rule by excluding ADR life differences from applicability under the rule.

The Commission does not agree. There is a distinction between life differences affected by the ADR provisions and other life differences. An example from the electric utility industry would be helpful to understand this distinction. Book depreciation allowed for utility generating plant is based on an average asset life of approximately 31 years for the industry, whereas tax depreciation, prior to the 1971 Revenue Act, permitted a 28-year life. The tax effects of the differences between these tax and book lives would be covered under the final rule.[111] As a result of the 1971 Revenue Act amendments to the Internal Revenue Code the ADR provision allows an asset's life to be shortened, for tax purposes, up to 20% of what its tax life otherwise would have been. The condition placed upon this allowance was that the utility could use the shortened life under the ADR provision only if the resulting tax effects were normalized.[112]

In Order No. 504, the Commission set up the accounting that would be required for the normalization of tax effects of life differences arising from the use of the ADR provisions. In several subsequent rate orders,[113] the Commission approved the normalization treatment of the tax effects of this life difference adopted by utilities so as to take advantage of the 20% shorter tax life of the asset. Thus, the ADR provisions do not fall under the applicability of the instant rule, since prior Commission opinions and orders have already specified (at least implicitly) the ratemaking treatment for these timing differences.

The final rule includes in § 2.202(a)(2) reference to "differences that result from the use of Class Life Asset Depreciation Range (ADR) tax provisions of the Internal Revenue Code" in the list of excluded items, in addition to the ones in the proposed rule. This paragraph of the final rule makes no other substantive changes to the proposed rule.

The life differences that would be covered under the final rule are the other life differences as described and measured in the staff study attached to the Notice, *e.g.*, the difference between 31 years for book depreciation and 28 years for tax depreciation in the above illustration. These are the life differences that the Commission indicated in Opinion Nos. 739 and 739-A as being covered under the Order No. 530 series.

B. *General Rules—§ 2.202(b).* The proposed § 2.202(b)(1) stated that rate applicants may elect to employ tax normalization in computing the tax component of their cost of service for all transactions covered by the rule. It also stated, in subparagraph (2), that the rate base must reflect the deduction and addition of specific accumulated deferred tax accounts resulting from the use of tax normalization.

As discussed below, the option that rate applicants be permitted to elect normalization has been revised. The final rule in § 2.202(b)(1) requires the applicant to apply tax normalization for all "miscellaneous" timing differences. Because the Commission finds that its policy rationale supporting tax normalization is correct for the utility and pipeline industries as a whole, and because the arguments for exceptions are unpersuasive, the Commission finds no basis for granting exceptions within the general rule itself. The final rule also provides that use of tax normalization will not be subject to challenge on a case-by-case basis. It should be emphasized, however, that the actual calculations under tax normalization are subject to scrutiny in individual cases.

Several commenters objected to the proposed provision that gave rate applicants the unilateral right to make the initial election to employ normalization. Concern was expressed for the due process rights of intervenors to object to the policies proposed by rate applicants. The commenters pointed out that the proposed rule would deny intervenors the opportunity to present evidence on the tax deferral versus permanent tax savings issue. It would also deny intervenors the opportunity to propose normalization where the rate applicant has proposed flow-through treatment.

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[111] The revenue impacts of the life differences measured in the staff study attached to the Notice refer to the tax effects of the differences between a book life of 31 years and a tax life of 28 years (Notice at 90, 45 F.R. at 22002).

[112] The Commission disagrees with the commenter's statement that ADR benefits "are not required to be normalized" (*Public Systems* at 24.) The Commission's position is the same as with accelerated depreciation—IRS permits the use of the faster tax write-off and shorter asset life only if normalization of the resulting tax effects is permitted by the regulatory commission. *See* Reg. § 1.167(a)-11(b)(6).

[113] In subsequent rate cases, the Commission approved the rates of utilities and pipelines, that included the normalization of timing differences associated with their use of ADR provisions for tax purposes. *See, e.g., Texas Gas Transmission* Docket No. RP74-25, Opinion Nos. 801 (May 31, 1977) and 801-A (July 29, 1977); *Transcontinental Gas Pipeline Co.*, Docket Nos. RP74-48 and RP75-3, Opinion No. 812 (July 20, 1977).

The Commission believes that normalization is the correct ratemaking policy for the reasons discussed in detail in the preceding Section II of the preamble. Since it is the preferred rate policy, the final rule requires the use of tax normalization by rate applicants. The Commission has afforded all interested persons an opportunity to comment on the tax normalization proposal. The Commission is unpersuaded by those objections. Finally, by requiring that tax normalization of these miscellaneous timing difference transactions be followed by rate applicants, the objection that intervenors would have no opportunity to propose tax normalization when the utility or pipeline elects flow-through is eliminated.

Arguments for case-by-case adjudication of tax normalization versus flow-through were also expressed by several commenters. Some of these commenters appeared to presume that the primary rationale for normalization was improved cash flow. Thus, the view was expressed that the desirability of a utility to employ tax normalization was dependent upon the factual circumstances relating to that utility or pipeline, primarily related to its cash flow needs. It was argued that many utilities and pipelines now are in healthy cash flow situations and that tax normalization should only be allowed on a case-by-case basis when improvements in cash flow were shown to be needed.

The Commission does not base its rationale for requiring tax normalization in this final rulemaking on utilities' or pipelines' need for cash flow improvement. (See detailed discussion in Section II–I.2, above.) Whether or not utilities are in a healthy cash flow position has not influenced the Commission's decision for or against requiring tax normalization. The Commission's determination to require tax normalization is based on many considerations, all of which are independent of the particular circumstances of a utility at a single point in time. Therefore, a general rule is more appropriate than a case-by-case determination.

Others argued that because of the inherent complexities of implementing tax normalization, normalization issues will be raised in many or most rate cases even if the Commission adopted the proposed normalization rule. Thus, there would be little savings in administrative convenience by adopting a general rule. The Commission disagrees. No issues have been raised in this proceeding that portend continued debate in rate proceedings after the institution of the final generic rule. Raising the specter of implementation or other problems without specific examples does not persuade the Commission against the generic approach.

The Commission does, however, make provision in § 2.202(c), discussed below for: (1) case-by-case determination of a proper way of handling these "miscellaneous" timing difference transactions that originated prior to this rule and were given flow-through treatment, and (2) handling the effects of tax rate changes. The case-by-case approach is used because the Commission has not yet adopted a cost of service method of uniform applicability for the utility and pipeline industries.

With respect to the rate base adjustments in § 2.202(b)(2) of the proposed rule, a number of commenters said that accumulated deferred taxes should be separated between those associated with plant in service and those associated with construction activities. It was argued that it is inconsistent with the interperiod equity rationale used to support normalization to require that the deferred taxes associated with construction activities be deducted from rate base. Rather, it was argued, these taxes should be deducted from the balance that is utilized for the calculation of the Allowance for Funds Used During Construction (AFUDC).

The Commission agrees with the underlying rationale of these comments. Deferred taxes arising from construction-related taxes and pensions, for example, reduce the financing requirements to be met from other sources during the construction period of a plant. Having the use of these interest-free funds results in benefits that the Commission has traditionally passed immediately through to customers by deducting the associated accumulated deferred taxes from rate base. But since these benefits arise from costs associated with the new plant, it is more equitable to allocate them over the service life of that plant. By using the construction-related accumulated deferred taxes as an offset to the balance used in the calculation of AFUDC (rather than rate base), the net plant value going into rate base when the new plant goes on line is reduced. In this way the benefits a company receives from having the use of deferred tax funds during the plant construction period would be reflected in lower costs to be allocated over the plant's operating life.

In order to accomplish such a change in the current procedures for deducting accumulated deferred taxes from rate base, however, several existing regulations of the Commission that were not subject to the Notice in this proceeding would have to be revised—*e.g.*, the formula for calculating AFUDC, the § 35.13 filing requirements for electric utilities and the § 154.63 filing requirements for natural gas pipelines. The Commission believes that these changes in its regulations should be a product of a separate proceeding. The final rule, in § 2.202(b)(2)(ii), requires that rate base be adjusted for all accumulated deferred taxes, including accumulated deferred taxes arising from construction-related timing differences and from other jurisdictional activities. By jurisdictional activities we mean all revenue and expense items that affect the jurisdictional cost of service (*e.g.*, regulatory commission expenses). It should be noted that accumulated deferred taxes arising from the types of timing differences excluded from this section (*e.g.*, accelerated depreciation) are also subject to § 202(b)(2) provisions. The rate adjustments in the final rule are mandatory.

The Commission notes that there may be situations in which newly created enterprises are in the process of constructing facilities for future service and do not currently have on file rates for an existing service. In such circumstances, the enterprise would have no rate base in which the deferred tax for construction-related timing differences may be reflected. Although not provided for in the final rule, the Commission believes in such circumustances that it would be appropriate to reduce the balance that is utilized for the calculation of AFUDC by the construction-related deferred taxes in order that future customers will properly receive the benefit of the time value of deferred taxes generated during the construction period.

A number of commenters responded to the Commission's request for comments on the gross-of-tax versus net-of-tax AFUDC rate methods, and substantial controversy has been engendered. The problems raised are difficult and do not lend themselves to easy, clear-cut decisions. The Commission has thus decided to sever this issue from the instant proceeding and combine any action taken on the gross-of-tax versus net-of-tax question with future revisions of the AFUDC formula.

One commenter requested that utilities be permitted the option of including accumulated deferred taxes in its capitalization at zero cost rather than using it as an offset to rate base. The commenter argued that this would allow consistency with some state commission policies.

The Commission does not believe that such consistency is necessary since there are many ratemaking approaches at this Commission which differ from state ratemaking policies. Nor would inclusion of deferred taxes in the capital structure be desirable. Under the special circumstances where rate base equals total capitalization, there is no difference in the effects on revenue requirements of the two methods. However, rate base is typically less than total capitalization. Under this circumstance, the effect of including accumulated deferred taxes in the capital structure at zero cost is to set revenue requirements at a higher level than if rate base deduction were used, and thus the full benefits realized by the utility in having the use of the deferred tax funds are not passed through to its customers.

C. *Special Rules—§ 2.202(c).* The proposed § 2.202(c) set forth the "Conditions" that rate applicants must follow to conform to the proposed rule. Subparagraph (1) stated the "all or none" condition with respect to the miscellaneous timing differences. Either the rate applicant could choose to normalize all of these timing differences or it could not normalize any. Subparagraph (2) explained the ratemaking treatment to be accorded the miscellaneous timing differences that arose prior to the institution of this rulemaking. Subparagraph (3) explained the conditions applicable to future rate filings by the applicant and how an election might be changed.

In the final rule, paragraph (c) is revised and renamed "Special rules." As the final rule (in § 2.202(b)) requires tax normalization of all miscellaneous timing differences, no provision is made for electing an option or for changing that election. There are two questions that the Commission addresses in § 2.202(c) of the final rule. One question is how to treat the effects of deferred taxes when there are tax rate changes. A related question (in terms of the ratemaking solution) is how to treat timing differences that had previously been flowed through.

The tax rate change problem arises when, for example, the tax rate is cut from 48 percent to 46 percent and the amounts provided for in rates and accumulated at a 48 percent tax rate for deferred taxes is in excess of that needed to provide for future tax liabilities to be determined at the 46 percent tax rate. The question is how to return these excess deferred taxes to consumers.

Some parties to this proceeding suggest that the proper way is to require that the reversal of the tax effects of each timing difference transaction be made at the same tax rate at which it was initiated. This is one of the approaches permitted under Accounting Principles Board Opinion No. 11 or generally accepted accounting practices. The Commission believes that this is a viable approach. However, the Commission believes that other approaches could also achieve reasonable and equitable results.

The second problem addressed in this paragraph is the ratemaking treatment to be accorded the tax effects of timing difference transactions that originated prior to this final rule and had been given flow-through treatment. To the extent that certain timing difference transactions were given flow-through treatment in the past, the deferred tax reserves may be in excess of or deficient from that required to provide for the associated future tax liabilities as they arise. Several comments expressed concern that the proposed rule was unclear on the treatment to be accorded prior flow-through timing differences.

Because of the equity considerations underlying the Commission's decision to require tax normalization, the Commission finds that it is appropriate to require all companies to make some provision in their deferred taxes for the tax effects of timing difference transactions that had previously been flowed through. As long as there are any timing difference transactions for which deferred tax provisions have not been made, there is some interperiod inequity in the rates to consumers. Similarly, when tax rates change and cause deferred tax reserves to become excessive or insufficient for the funding of future tax liabilities at current tax rates, there is an interperiod inequity in rates that can be lessened by some policy that would adjust the deferred tax reserves over a reasonably short period of time.

As revised, the final rule requires rate applicants to begin the process of making up deficiencies in or eliminating excesses in their deferred tax reserves so that, within a reasonable period of time to be determined on a case-by-case basis, they will be operating under a full normalization policy. The final rule in § 2.202(c)(2) requires a rate applicant to compute the income tax component in its cost of service by making provision for any excess or deficiency in its deferred tax reserves resulting both from the prior flow through treatment of timing differences and from tax rate changes.[114]

The final rule also states that this provision must be consistent with a Commission-approved ratemaking method made specifically applicable to the rate applicant. If no Commission-approved ratemaking method has been made specifically applicable to the rate applicant, the Commission requires, in § 2.202(c)(3), that the rate applicant advance some method that would accomplish the same purpose. The appropriateness of the method will be adjudicated in the next rate proceeding.

Since the appropriateness of any method to accomplish the objective of full normalization at current tax rates has not been analyzed by the Commission on a generic basis, the Commission is, at this time, requiring resolution of this problem on a case-by-case basis. As the issue is resolved in a number of cases, one or more specific methods (*e.g.*, the "South Georgia Method")[115] that would have wide applicability may be adopted.

We are reluctant to incorporate in § 2.202(c) of the rule reference to the treatment to be accorded timing difference transactions excluded from this section (by § 2.202(a)) but which were flowed through in the past since they may be considered beyond the scope of the instant rule. However, since the Commission finds tax normalization to be the proper method for handling timing differences in general, we encourage applicants to include those transactions as part of their cost of service calculations pursuant to § 2.202(c).

About half of the utility commenters expressed concern about the "all or none" condition contained in paragraph (c) of the proposed rule. The utilities alleged that elaborate and expensive accounting procedures would have to be implemented to identify timing differences that may have insignificant effects on the cost of service. They also stated that the costs of keeping track of immaterial timing differences and those having short-term turnarounds exceeded any benefits that may be realized. It was recommended that a materiality standard be made part of the rule.

Many of the commenters also expressed concern about the costs of maintaining different treatment for state and federal accounting and ratemaking. This problem relates primarily to electric utilities where the proportion of business regulated by FERC is small in many instances. It was recommended that the normalization requirement should apply only to those timing differences normalized by the predominant regulatory authorities.

The Commission does not agree with the utilities' claims of excessive costs in normalizing immaterial and short-term turnaround timing differences. Companies keep track of the timing differences for their IRS tax filings. Therefore, they can readily track and normalize these timing differences for ratemaking purposes. Many utilities did not complain about the lack of a materiality standard, and those that did complain relied on simple assertions of administrative burden without any quantification of costs. We are not persuaded that such burdens are excessive as a general matter.

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[114] One commenter was concerned that *any* previously accumulated deferred taxes could be used in this calculation. This concern is unfounded because only previously accumulated deferred taxes that would have been allocated to wholesale customers for the specific timing difference would be relevant here.

[115] *South Georgia Natural Gas Co.*, Docket No. RP77-32, order issued May 5, 1978.

One utility proposed the use of pooling for timing differences that do not involve major amounts of dollars. The Commission finds this an acceptable method for reducing the costs of compliance.

Subparagraph (3) in § 2.202(c) in the proposed rule provided that a rate applicant had to make the election to normalize at the time of its next filing. Since the election provision has been deleted in the final rule, this subparagraph has been eliminated. A rate applicant must now adopt tax normalization for miscellaneous timing differences at the time it makes its next rate filing, following the effectiveness of this rule.

D. *Definitions*—§ 2.202(d). Section 2.202(d) in the proposed rule contained the definitions used in the rule. Only one comment was received on the definition section, and that comment was on the definition of "tax normalization." The commenter stated that the definition was inconsistent with the use of the terms in subparagraphs (b)(1) and (c)(1) of the proposed rule, in that "tax normalization" was used as a concept to be applied to a transaction in (b)(1) and (c)(1), but the (d)(1) definition implied an overall procedure to be applied to revenues and expenses taken together.

The Commission agrees that there was an inconsistency between the definition of "tax normalization" in the proposed rule and the way the concept was used. In the final rule, the Commission revises the definition of tax normalization to refer to individual timing difference transactions rather than amounts of expenses and revenues, thus assuring consistency with the use of the term "tax normalization" in the other parts of the rule.

The Commission has, on its own motion, modified the definition of "rate applicant" to refer simply to the Federal Power and Natural Gas Acts rather than to specific sections of those Acts.

Finally, two definitions have been added. First, "tax effect" is defined as "the tax reduction or addition associated with a specific expense or revenue transaction." This was done to clarify the rule.

Second, the term "Commission-approved ratemaking method", used under paragraph (c), is defined as "a ratemaking method approved by the Commission in a final decision, including approval of a settlement agreement containing a ratemaking method only if such settlement agreement applies that method beyond the effective term of the settlement agreement." This definition specifically excludes approval of settlement agreements that contain a ratemaking method whose term is coextensive with the term of the settlement agreement.

As a general matter, Commission approval of a settlement does not mean an approval of the methods used to arrive at the settlement rates. However, by including, for purposes of this rule, settlement-approved methods that extend beyond the period of the settlement, agreement by the parties not to litigate the issue in future rate cases is preserved and encouraged.

Commission Findings

For the reasons set forth above, and in addition to the findings made above, *the Commission further finds that:*

(1) The rates fixed by the Commission in all cases subject to the Order Establishing Interim Procedures issued June 8, 1979 under Docket Nos. R-424 and R-446, which use tax normalization principles, need no longer be subject to the refund contingency established by that Order;

(2) Tax normalization is the preferred ratemaking policy for the tax effects of

timing difference transactions covered under Docket Nos. RM80-42, R-424, R-446.

(3) Good cause has been show to incorporate this preferred policy into a general rule; and

(4) These findings are necessary and proper for implementing the Natural Gas Act and the Federal Power Act.

Orders

Based on the findings and the reasons set forth above, *the Commission orders that:*

(A) The refund contingencies relating to tax normalization imposed in all cases subject to the Order Establishing Interim Procedures issued June 8, 1979 under Docket Nos. R-424 and R-446 shall be removed as of the date a final rule issued in this proceeding becomes effective.

(B) The Commission further orders that Part 2 of Chapter I, Title 18, Code of Federal Regulations is amended, as set forth below, that amendment to be effective sixty days after issuance of this order.

(Federal Power Act, 16 U.S.C. 792, *et seq.;* Natural Gas Act, 15 U.S.C. 717 *et seq.;* Department of Energy Organization Act, 42 U.S.C. 1701 *et seq.;* Administrative Procedure Act, 5 U.S.C. 553 *et seq.*)

By the Commission.

Lois D. Cashell,
Acting Secretary.

[¶ 30,255]

46 F. R. 27911 (May 22, 1981)

18 CFR Part 281

[Docket No. RM79-15; Order No. 145]

Revision of Schedule of Filing Annual Revisions To Index of Entitlements for Priority 2 (Essential Agricultural) Uses of Natural Gas; Implementation of Section 401 of the Natural Gas Policy Act

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Commission by this final rule amends its Regulations in Part 281, Subpart B that establish a filing schedule by which interstate pipelines collect customer data regarding essential agricultural uses, prepare revisions to their curtailment plans to reflect the data collected, and file these revisions with the Commission. This rule adds approximately 45 days to the filing schedule in order to provide additional time for the interstate pipelines to prepare the revisions to their curtailment plans.

EFFECTIVE DATE: Date of issuance, May 14, 1981.

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Robert Schroeder, Office of Pipeline & Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8828.

May 14, 1981.

The Federal Energy Regulatory Commission adopts final regulations that revise the schedule for filing annual revisions to the index of entitlements for priority 2 (essential agricultural) uses of natural gas.

I. Background

Title IV of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3391-3394) creates new priority classifications for certain uses of natural gas. Section 401 of NGPA established the category of essential agricultural uses of natural gas that are not to be curtailed unless necessary to protect users of a higher priority.

The Commission implemented section 401 through a series of orders issued in Docket No. RM79-15 that essentially reorder curtailment priorities. Under the newly reordered priorities, uses of natural gas in residences, certain commercial establishments, schools, hospitals, and for certain other purposes constitute Priority 1, and essential agricultural uses of natural gas constitute Priority 2.[1] When the program was implemented two years ago, the designated pipelines[2] were required to reorder their individual curtailment plans by incorporating the curtailment priorities described in section 401. Thereafter on an annual basis, these pipelines are required to update their curtailment plans by filing with the Commission revised tariff sheets that contain an index of entitlements for Priority 2, essential agricultural uses.

In order to revise the index of entitlements, it is necessary for the interstate pipelines to collect data from end-users, distributors, and other interstate pipelines regarding the current requirements for essential agricultural uses of natural gas (§ 281.211). These data are then used by the interstate pipeline to determine if and to what extent it must revise its index of entitlements in order to allocate sufficient volumes of natural gas to meet the essential agricultural requirements of its customers.

Each interstate pipeline is required to prepare and transmit a draft index of entitlements (§ 281.212) to each of its customers and to its Data Verification Committee (§ 281.213). Under the regulations, the customers have an opportunity to protest the interstate pipeline's proposed allocation of natural as volumes to the categories of users. The Data Verification Committee is required to analyze and prepare a report to assist the pipeline in finalizing the index of entitlements that will be filed with the Commission.

Taking into consideration customer protests and the report of the Data Verification Committee, the interstate pipeline then makes final adjustments to the draft index. The index is filed with the Commission as an amendment to the pipeline's currently effective tariff under section 4 of the Natural Gas Act.

These regulations include a schedule of filing and notification dates so that the approved indices can be effective on November 1 for the winter season. Since this program was adopted, the Commission has revised these dates when it determined revisions were necessary to provide all persons obligated under the program sufficient time to prepare the required documents. With this experience, the Commission has now determined that additional revisions are necessary.

II. Summary of Revised Schedule

By this final rule, the Commission adopts the following revised schedule:

June 15—Essential agricultural users are required to file with direct suppliers data regarding current natural gas requirements.

June 30—Local distribution companies are required to file with their interstate suppliers data regarding their customers' essential agricultural use requirements.

July 15—Interstate pipelines are required to file with their direct interstate suppliers their natural gas requirements for essential agricultural uses.

August 1—Interstate pipelines are required to provide their customers and Data Verification Committee with a draft index of entitlements.

August 15—Protests to the draft index of entitlements are required to be filed with the Data Verification Committee.

September 1—The Data Verification Committee is required to submit its report to the interstate pipeline.

September 15—Interstate pipelines are required to file revisions to the index of entitlements and the Data Verification Committee report with the Commission.

November 1—Revisions to the index of entitlements for each interstate pipeline become effective if approved by the Commission.

The effect of this new schedule is to add approximately 45 days to the schedule in order to provide additional time to the interstate pipelines to prepare the index of entitlements and to provide the Commission with additional time to consider these indices before becoming effective on November 1. This schedule moves forward from July 31 to June 15 the date the essential agricultural users are required to file data with their direct suppliers. Thirty days of this additional time were allocated to expand the period of time within which the interstate pipelines must analyze all the pertinent customer data and must file the revisions to the index of entitlements with the Commission. An additional 15 days were allocated to expand the period of time within which the Commission must review the index of entitlements filed by each pipeline.

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[1] Order No. 29, Docket No. RM79-15, issued May 2, 1979, 44 FR 26855, May 8, 1979. Order No. 29 was amended in Order Nos. 29-A, issued June 15, 1979 (44 FR 37499, June 27, 1979), 29-B, issued July 20, 1979 (44 FR 45922, August 6, 1979) and 29-C, issued October 22, 1979 (44 FR 61338, October 25, 1979).

[2] Interstate pipelines obligated by the regulations implementing section 401 are designated in § 281.202. Certain of the interstate pipelines have complied with section 401 without filing an index, pursuant to adjustments under Section 502(c) of the NGPA.

III. Section-by-Section Analysis

A. Section 281.211

Filing by Essential Agricultural Users. Subparagraph (b)(1) is amended by changing the date of "July 31, 1979" to "June 15 of each year". Under the amended regulation the essential agricultural users are required to file with their suppliers the data regarding current essential agricultural uses by June 15 of each year. This provides the additional 45 days to the schedule that is allocated as described above. Although this moves forward the filing date for the essential agricultural uses, the Commission does not believe any hardship will result because the filing requirement is minimal and many, if not all, of these users have previously participated in this program.

Filing by local distribution companies. Subparagraph (b)(2) is amended by substituting "June 30 of each year" for "August 15, 1979". This amendment preserves the 15 day interval under the current schedule between the date the essential agricultural users file with their direct suppliers and the date the local distribution companies must file with the interstate pipelines.

Filing by Interstate pipelines. Subparagraph (b)(3) is amended by substituting "July 15 of each year" for "August 31, 1979". This amendment preserves the 15 day interval under the current schedule between the date the local distribution companies must file with their direct suppliers and the date the interstate pipelines must file data with their direct interstate pipeline suppliers.

B. Section 281.213

Data Verification Committee. Paragraph (c) is amended by substituting "August 15 of each year" for "September 21, 1979" and by deleting the last sentence of the paragraph. This expands by seven days the time for customers to file protests to the draft index of entitlements.

Paragraph (e) is amended by substituting "September 1 of each year" for "September 23, 1979" and by deleting the last sentence of the paragraph. This expands from nine to 30 days the period for the Data Verification Committee to prepare its report on the draft index of entitlements.

C. Sections 281.204 and 281.205

Sections 281.204 and 281.205 are amended in subparagraph (b)(2) and subparagraph (c)(2), respectively, by substituting "September 15" for "October 1". These amendments establish September 15 as the date the interstate pipelines must file the index of entitlements with the Commission. The total period of time for the interstate pipelines to prepare the index from the data collected is expanded by approximately 30 days.

Subparagraph (b)(4) is deleted. The election available to the interstate pipelines to file the index of entitlement on November 1 instead of October 1 under current regulations is no longer necessary. After two years, the interstate pipelines should be sufficiently familiar with the filing schedule that the election of additional time is unnecessary particularly in view of the additional time incorporated by this rule into the schedule.

Subparagraph (a)(2) is deleted also because it establishes dates effective for 1979 that are no longer necessary.

D. Section 281.216

Section 281.216 that revised the schedule for 1980 is no longer necessary and is therefore deleted.

E. Section 281.212

Paragraphs (b) and (c) are revised to substitute "August 1 of each year" in lieu of "September 14, 1979" as the date the interstate pipeline must serve the draft index of entitlements on the customers and on the Data Verification Committee. Paragraph (d) that establishes the filing date for years subsequent to 1979 is unnecessary because of the amendment to paragraphs (b) and (c) and is therefore deleted.

IV. Effective Date of Final Rule

The amendments to 18 CFR Part 281 of the Commission's regulations adopted herein are effective immediately upon issuance. These amendments add approximately 45 days to the filing schedule applicable to agricultural users, local distribution companies and interstate pipelines for the collection of data and the preparation and filing of the revisions to the index of entitlements of natural gas for essential agricultural uses.

Because this rule adopts procedural changes in the Commission's regulations, public comment procedures are not required under section 553(b) of the Administrative Procedure Act (APA), 5 U.S.C. 553(b).

For the reasons stated above regarding the advantages of adding approximately 45 days to the filing schedule, the Commission believes that good cause exists, in accordance with section 553(d) of the APA, 5 U.S.C. 553(d), to waive the 30-day notice and to make this rule effective immediately.

(Natural Gas Policy Act of 1978 (15 U.S.C. 3301–3432); Department of Energy Organization Act (42 U.S.C. 7101 *et seq.*); E.O. 12009, 42 CFR 46267 (1978))

In consideration of the foregoing, the Commission amends §§ 281.204, 281.205, 281.211, 281.212, 281.213, and 281.216 of Part 281, Subchapter I of Chapter I, Title 18 of the Code of Federal Regulations as provided below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,256]

46 F.R. 29459 (June 2, 1981)

18 CFR Part 141

[Docket No. RM81-3; Order No. 146]

Final Rule To Eliminate Requirement of Federal Entities To File Report for Electric Utilities, Licensees and Others, "Annual Report (Class A and Class B)"

Issued May 26, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) hereby eliminates the requirement for Federal entities, which generate, transmit, distribute or sell electric energy, to file the "Annual Report for Electric Utilities, Licensees and Others (Class A and Class B)," FPC Form No. 1 and its modified versions, which were previously prescribed by 18 CFR 141.1.

The information collected in filings by these Federal entities of Form No. 1 and its modified versions includes summary financial data, balance sheet supporting data, income statement supporting data and electric plant, sales, operating and statistical data.

These Federal Form No. 1 data have been collected in conjunction with the Commission's headwater benefits program and Federal rate cases. Some of this information supplements and duplicates other data submitted for

assessment of headwater benefits and for Federal rate filings. The Commission has determined that these data are not useful for the performance of the Commission's regulatory responsibilities and should accordingly be eliminated in their entirety.

There is also currently pending at the Commission a rulemaking proceeding to revise Form No. 1—the major annual report filed with the Commission by *non*-Federal (*i.e.*, investor-owned) Class A and Class B electric utilities, licensees and other entities. (*See* Notice of Proposed Rulemaking, issued July 10, 1980, Docket No. RM80–55, 45 FR 47704, July 16, 1980.) That proceeding is entirely separate and distinct from the instant rulemaking, which solely addresses the versions of Form No. 1 filed by *Federal* entities that generate and sell electricity.

The Economic Regulatory Administration and the Office of Conservation and Renewable Energy in the Department of Energy have stated that they utilize the data reported by Federal entities pursuant to § 141.1. Either or both of these agencies may assume collection of this information under their own authority. In order for these agencies to have sufficient time to complete rulemaking proceedings to assume this responsibility, the Commission is delaying the effective date of the elimination of this reporting requirement from its regulations until December 31, 1981.

By an order of November 5, 1980, however, the Commission suspended the application of § 141.1 to Federal entities for calendar years 1980 and thereafter until further notice; thus § 141.1 reports from Federal entities are *not* now required for calendar years 1980 or 1981. Unless the Department of Energy or other Federal entity requires the collection of these data, no further Federal versions of Form No. 1 will be required to be submitted.

EFFECTIVE DATE: December 31, 1981.

FOR FURTHER INFORMATION CONTACT: Ellen Brown, Office of Program Management, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Room 3317, Washington, DC 20426, (202) 357–8182.

SUPPLEMENTARY INFORMATION:

Issued: May 28, 1981.

In the matter of an Annual Report for Electric Utilities, Licensees and Others (Class A and Class B): Filings by Federal Entities Pursuant to § 141.1; Docket No. RM81–3, Order No. 146, final rule.

By this rulemaking the Federal Energy Regulatory Commission (Commission) eliminates the requirement for Federal entities to file information with the Commission, pursuant to 18 CFR 141.1, "Form No. 1, Annual Report for Electric Utilities, Licensees and Others (Class A and Class B)." This rulemaking is part of the Commission's ongoing program to evaluate all of the data which are required by the Commission for regulatory purposes and to eliminate unnecessary reporting requirements.

There is also currently pending at the Commission a rulemaking proceeding to revise Form No. 1—the major annual report filed with the Commission by *non*-Federal (*i.e.*, investor-owned) Class A and Class B electric utilities, licensees and other entities. (*See* Notice of Proposed Rulemaking, issued July 10, 1980, Docket No. RM80–55, 45 F.R. 47704, July 16, 1980.) That proceeding is entirely separate and distinct from the instant rulemaking which relates only to *Federal* entities that generate and sell electricity.

I. Background

A. Requirement to File Federal Form No. 1

The Commission is authorized to require the submission of information pursuant to sections 303 and 311 of the Federal Power Act (16 U.S.C. 792–828c). Section 141.1 of the Commission's regulations requires the annual filing of information from Class A and Class B electric utilities, licensees and other entities, including Federal entities engaged in the generation, transmission, distribution or sale of electric energy.[1] In brief, the prescribed filing includes summary financial data; balance sheet supporting data; income statement supporting data; and electric plant, sales, operating and statistical data.

The reports which have been submitted by Federal entities pursuant to § 141.1 are all modified versions of Form No. 1. The modified Form No. 1 reports have been filed by a variety of Federal entities, including Power Marketing Administrations within the Department of Energy, and the Water and Power Resources Service and Bureau of Indian Affairs within the Department of Interior. Another modified version of Form No. 1 is "Form No. 1002," an unofficial version of the Form No. 1 which has been filed by several projects operated by the Army Corps of Engineers and certain other agencies.

These Federal reports were required to be filed on or before December 31 of each year and were based on data from the immediately preceding fiscal year (October 1 through September 30). On November 5, 1980, however, the Commission issued an order to suspend, until further notice, the 1980 filing and future filings of information by Federal entities pursuant to 18 CFR 141.1 (45 FR 74715, November 12, 1980). The Notice of Proposed Rulemaking to eliminate these Federal filings was issued on December 30, 1980 (Docket No. RM81-3, 46 FR 1743, January 7, 1981).

B. Use of the Federal Form No. 1 Data by the Commission

The information collected from Federal agency filings of the Form No. 1 [2] has been used in the Commission's headwater benefits program (*see* 18 CFR 11.25–11.31, 13.1) and in Federal rate cases (*see* Delegation Order No. 0204-33, December 21, 1978, 43 FR 60636, December 28, 1978, and the Pacific Northwest Electric Power Planning and Conservation Act of 1980, Pub. L. 96-501).

The Commission stated in the December 30, 1980 Notice of Proposed Rulemaking that some of the information in the Form No. 1 Federal filings supplements and duplicates data submitted to the Commission for assessment of headwater benefits and for Federal rate filings. Because the data filed by Federal entities pursuant to § 141.1 were not useful for the performance of the Commission's regulatory responsibilities, the Commission proposed to eliminate these data in their entirety.

The Notice of Proposed Rulemaking further provided that revisions to the Commission's headwater benefits and Federal rate filing requirements are expected in 1981 and may include data similar to those proposed for deletion. In the meantime, the Commission would continue to use current Federal rate and headwater benefits submissions and specific data requests to obtain information needed for review in these areas.

Finally, the Commission noted that the Energy Information Administration (EIA) may require the collection of the data for itself or for some other sector within the Department of Energy. Another Federal agency could also require these data. The Commission provided that if EIA or another agency should make such a determination during this rulemaking proceeding, the Commission would issue a final rule with a delayed effective date which would formally eliminate the requirement for Federal entities to file Form No. 1 with the Commission. During this period of time before the final rule became effective, such agencies could justify the need for the data and receive approval for the collection of this information under their own authority.

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[1] A Class A electric utility, licensee or other entity is one having annual electric operating revenues of $2,500,000 or more. A Class B electric utility, licensee or other entity is one having annual electric operating revenues of $1,000,000 or more but less than $2,500,000.

[2] All references to the Federal filings of Form No. 1 in this rulemaking include Federal filings of the Form No. 1002.

The Commission specifically requested that comments address the following questions:

1. Does the proposed elimination of data affect any Commission regulatory function?
2. Is there any reason for continued collection of these data by another Federal agency? Suggestions for the continued collection of data which have been proposed for elimination should identify the proper agency and the purpose for the proposed collection of the data.

III. Summary of Comments

The Commission received six comments in response to the Notice of Proposed Rulemaking in this docket.[3]

East Kentucky Power Cooperative said that the proposed elimination of data would not affect any of the regulatory functions of the Commission and that the continued collection of the data by another Federal agency would not be necessary.

The Office of the Chief of Engineers of the Department of the Army concurred in the proposed elimination of the data. (Sixty-seven of the eighty-one Federal Form No. 1 reports which have been collected by the Commission were filed by projects under the control of the Chief of Engineers.)

South Carolina Electric and Gas Company (SCE&G) opposed the elimination of the entire requirement for Federal entities to file Form No. 1 although it did not oppose "streamlining" the requirement. SCE&G put forth three arguments against elimination of this requirement. First, the data in these filings did serve a Commission regulatory function by providing both the Commission and regulated (investor-owned) utilities with important information for deciding price squeeze issues. Second, the collection of the data served the "public's right to know." SCE&G contended that while information about investor-owned utilities could be obtained by the public from their Federal, State and (often) local regulatory authorities, information about publicly-owned utilities was not so readily available. According to SCE&G, elimination of this requirement for Federal entities would make matters worse and contradict the spirit of the Public Utility Regulatory Policies Act of 1978 (PURPA) (16 U.S.C. 2601–2645) which prescribed greater and more meaningful public dissemination of utility operating data. Finally, SCE&G argued that public power operations have historically served as a comparative model for investor-owned utility operations. If information about these Federal facilities became unavailable, it would be difficult to use such facilities as a model. Furthermore, it would be unfair for investor-owned utilities to be subjected to a different measuring standard than their "models."

Southwestern Power Administration (Southwestern), which files the Federal Form No. 1 and also uses the Form No. 1002 for projects constructed and operated by the United States Army Corps of Engineers (USCE), also objected to the complete deletion of this Federal reporting requirement. Southwestern stated that the data were in a concise format and were consistent and simple to extract for internal use. Without this form, Southwestern asserted that it would have to develop its own format to collect information necessary to analyze critical operating trends. Furthermore, such a revised format could be used only for internal use, while the current Form No. 1 is used as an official document. Southwestern argued that this proposed deletion would result in very little, if any, reduction in its burdens.

Finally, Southwestern noted that certain of the data collected in the current Form Nos. 1 and 1002 are used for Federal rate filings and power repayment studies. These data would have to be obtained elsewhere or in a new form to replace Form Nos. 1 and 1002. Southwestern did, however, favor some type of revision to the current Federal Form No. 1 requirements.

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[3] Energy Information Administration, Economic Regulatory Administration, Southwestern Power Administration (all within the Department of Energy); Office of the Chief of Engineers (Department of the Army); East Kentucky Power Cooperative, Incorporated; South Carolina Electric and Gas Company.

Comments received from both the Energy Information Administration (EIA) and the Economic Regulatory Administration (ERA)[4] stated that ERA is interested in assuming the responsibility for collecting the data reported in the Federal Form No. 1. ERA added that certain of the information reported therein is not available elsewhere and that this form is more detailed than other sources of data respecting Federal utilities.

IV. Conclusions

After careful consideration of the comments submitted in this proceeding, the Commission concludes that it can no longer justify the collection of the data which Federal entities have previously filed with the Commission pursuant to § 141.1; in its current format, the information is not useful for the performance of the Commission's regulatory responsibilities. As a matter of policy, the Commission believes it should not require the reporting of data which are not supportive of its regulatory responsibilities. However, ERA has determined that the collection of data in the Federal Form No. 1 is necessary to discharge its statutory responsibilities. In addition, the Office of Conservation and Renewable Energy within the Department of Energy also uses the data reported in the Federal Form No. 1.

In consideration of the comments of SCE&G, the Commission offers the following responses: First, SCE&G argued that the Federal Form No. 1 filings provided information for deciding price squeeze issues, but failed to specify the way in which the information was used for this purpose. Furthermore the Commission has never encountered a price squeeze issue in any case involving a Federal entity since *F.P.C. v. Conway Corporation* first established the price squeeze issue (426 U.S. 271 (1976); *aff'g* 510 F.2d 1264 (D.C. Cir. 1975)).

Second, SCE&G stated that the collection of the Federal Form No. 1 data served the public's right to know and that the reporting requirement provided a model for investor-owned utility operations. The Commission believes that it should not continue to require the reporting of information which is not used in its decisional process since the data that the Commission needs for regulatory purposes can be obtained from headwater benefits and Federal rate submissions and from specific requests for information. However, energy information which is vital to the public may be collected by the Energy Information Administration (EIA) which is specifically authorized by the Department of Energy Organization Act (42 U.S.C. 7101–7352) to gather that kind of data. In the absence of such a general information-collection role, the Commission will not continue to require this additional reporting burden.

Finally, SCE&G contends that the elimination of the Federal Form No. 1 data contradicts the policy of PURPA. The Commission believes that this rulemaking does not violate PURPA, for the following reasons: (1) The data gathered by the Commission pursuant to PURPA (section 133) are used by State commissions to enhance the goals of PURPA; (2) State commissions have no ratemaking responsibilities with respect to Federal entities; (3) the Commission has no authority to confirm, approve or disapprove rates on the basis of PURPA goals; and (4) there is no correlation between PURPA and the Federal Form No. 1. The Commission recognizes that the "spirit" of PURPA favors the dissemination of public utility information. However, upon balancing the significant burden of collecting data which are not used in the performance of commission statutory responsibilities against the general need for the information by the public and by utilities as a model for their own operations, the Commission has determined that elimination of the burden is a more essential consideration with respect to the Federal Form No. 1.

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[4] ERA cited the following legal authority for its own proposed continuation of data collection by means of the Federal Form No. 1: Federal Power Act, at section 202(a); Federal Energy Administration Act of 1974 (15 U.S.C. 761–790(h) at sections 5(a) and (b), 13(b)); Energy Supply and Environmental Coordination Act of 1974 (15 U.S.C. 791–798) at section 11(a) and (e); Department of Energy Delegation Order No. 0204–4 (October 1, 1977).

With regard to the comments of Southwestern, this Commission believes Southwestern will not have to develop a new form to collect similar data for its internal use. While Southwestern may decide to continue collecting data in the format previously set out in § 141.1, it will no longer be required *by Commission regulations* to collect or file such data.

The Commission has forwarded to ERA and to the Office of Conservation and Renewable Energy copies of the comments received in this docket because these agencies have shown considerable interest in assuming the responsibility for this data collection.

The Commission issues this final rule to discontinue filings by Federal entities pursuant to § 141.1 with an effective date of December 31, 1981. The ERA and the Office of Conservation and Renewable Energy should, therefore, have a sufficient time to complete their own rulemaking proceedings to effect similar Federal Form No. 1 data collection and to receive clearance from the Office of Management and Budget for the collection of these data. The final rule will actually formalize the *status quo* because the requirement for Federal entities to file Form No. 1 has been suspended since November 5, 1980.

V. Public Procedure and Effective Date

The Commission has complied with 5 U.S.C. 553 by providing public notice and an opportunity to participate in this rulemaking. The final rule in this docket will be issued with an effective date of December 31, 1981 so that ERA and the Office of Conservation and Renewable Energy may institute their own rulemaking proceedings to assume the responsibility for collecting data from Federal entities similar to those required by § 141.1 of the Commission's regulations.

[Federal Power Act, 16 U.S.C. 792–828c; Department of Energy Organization Act, 42 U.S.C. 7101–7352; E.O. 12009, 3 CFR 142 (1978)]

In consideration of the foregoing, the Commission herein eliminates the requirement for Federal entities to file the "Form No. 1, Annual Report for Electric Utilities, Licensees and Others (Class A and Class B)," including all modified versions of such Form No. 1, in accordance with 18 CFR 141.1, and revises Part 141 of Chapter I, Title 18 of the Code of Federal Regulations, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,257]

46 F. R. 29697 (June 3, 1981); 46 F. R. 32237 (June 22, 1981)

18 CFR Part 271

[Docket No. RM81-31; Order No. 149]

Clarification of Regulations Regarding New, Onshore Production Wells

Issued: May 28, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission clarifies the definition of "new, onshore production well" contained in § 271.303 of its regulations. The amendment, which effects no substantive change in the rule, provides that a determination that a well qualifies as a "new, onshore production well" applies only to gas produced from the proration unit (or units) on the basis of which the determination was obtained.

EFFECTIVE DATE: December 1, 1978.

FOR FURTHER INFORMATION CONTACT:

Craig Ellis, Office of General Counsel, Room 4006E, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357–8316

Howard Kilchrist, Office of Pipeline and Producer Regulation, Room 6112, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357–8585

SUPPLEMENTARY INFORMATION: By this rule the Federal Energy Regulatory Commission (Commission) amends § 271.303 of its regulations. Section 271.303 is contained in Subpart C (relating to new, onshore production wells) which implements section 103 of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3313). The amendment clarifies the definition of "new, onshore production well."

I. Background

On August 20, 1979, the Commission issued final regulations implementing section 103 of the NGPA.[1] A "new onshore production well" is defined in paragraph (c) of section 103 as follows:

> (c) *Definition of New, Onshore Production Well.* For purposes of this section, the term "new, onshore production well" means any new well (other than a well located on the Outer Continental Shelf)—
>
> (1) The surface drilling of which began on or after February 19, 1977;
>
> (2) Which satisfies applicable Federal or State well-spacing requirements, if any; and
>
> (3) Which is not within a proration unit—
>
> (A) Which was in existence at the time the surface drilling of such well began;
>
> (B) Which was applicable to the reservoir from which such natural gas is produced; and
>
> (C) Which applies to a well (i) which produced natural gas in commercial quantities or (ii) the surface drilling of which was begun before February 19, 1977, and which was thereafter capable of producing natural gas in commercial quantities.

The definition of "new, onshore production well" in the regulations did not embellish the statutory definition.[2]

Identification of gas which may be sold at the section 103 price depends, in part, on the proration unit from which the gas is produced; *i.e.*, whether proration units were applicable to the reservoir when the well was drilled; whether other wells had already been drilled into such a unit; etc. If a well is completed for production into two proration units, one completion location may qualify under section 103 as a new, onshore production well, while the other may not. A determination that a well qualifies as a new, onshore production well covers only gas produced from the proration unit(s) considered in qualifying the gas. If a producer obtains a section 103 determination and subsequently completes in a proration unit not considered in the prior determination, the prior determination does not qualify gas produced from the new proration unit for the section 103 price.

It has come to the Commission's attention by way of adjustment filings and informal contacts with Commission staff that some producers have not understood that qualification under section 103 applies only to production from particular proration units.[3] Some producers who have received a determination by a jurisdictional agency that gas is eligible for a price under section 103 have failed to submit a subsequent application for determination where they later produce gas from the same well, but from a different proration unit.

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[1] Order No. 43, "Final Rule Amending Regulations on Natural Gas from New, Onshore Production Wells and Amendment to the Filing Requirements in § 274.204 of the Interim Regulations," Docket No. RM79–72 (issued August 20, 1979) 44 Fed. Reg. 49651 (August 23, 1979). Order No. 43–A, "Order Granting In Part and Denying in Part Rehearing of Order No. 43 and Amending Regulations," Docket No. RM79–72 (issued Nov. 19, 1979) 44 Fed. Reg. 67106 (November 23, 1979).

[2] Prior to this amendment that definition, in § 271.303, read: For purposes of this subpart, the term "new, onshore production well" means a well which a jurisdictional agency has determined, in accordance with Parts 274 and 275, to be a new, onshore production well (as defined in section 103(c) of the NGPA).

[3] After staff initiated work on this rulemaking a petition for clarification or amendment of the

II. Clarification

The Commission did not intend that a section 103 eligibility determination cover gas produced from the same well from proration units not considered during the determination. The Commission intended that such a determination apply only to gas produced from the proration unit(s) on the basis of which the determination was obtained. In light of the above, we are clarifying the definition of "new, onshore production well" in § 271.303 by expressly providing that a determination that a well qualifies under section 103 applies only to gas produced from the proration unit (or units) on which the determination was based.

III. Effective Date

Because this amendment effects no substantive change in the rule but is necessary only for proper implementation, the Commission finds that public notice and comment is unnecessary. For the same reasons, the amendment is being made effective as of December 1, 1978, the date the original regulations became effective. (43 FR 56448, December 1, 1978.) In the absence of Commission guidance prior to issuance of this clarification, some producers have interpreted the statute and the regulations as authorizing collection of the section 103 price for sales from all proration units in a wellbore where only one of the proration units received a section 103 determination. Where the producers did rely on such a misinterpretation (and the gas from the subsequent proration unit is eventually determined to qualify for the section 103 price) the Commission finds it would be inequitable to insist upon refunds for deliveries which occurred prior to 60 days from the issuance of this clarification. To avoid refund requirements in such cases, an application for a determination must be filed with a jurisdictional agency no later than 60 days after issuance of this rule, and the final determination must qualify the gas for the section 103 maximum lawful price.

We are aware that in many cases the producers were unaware of the necessity to file an application for each section 103 proration unit in a wellbore until some time after deliveries began from different proration units in the same wellbore. For example, some producers became aware of the proper interpretation as a result of NGPA regional meetings held throughout the country, or purchasers' refusal to pay the section 103 price, and thereafter filed the necessary section 103 applications. Other producers collected under section 103 prior to filing for a section 103 determination for the subsequent proration unit. Some made refunds when they became aware of the filing requirement while others have yet to make refunds. We believe that producers should be permitted to collect the section 103 price for the period they were unaware of the proper interpretation of the definition of "new, onshore production well" provided the contracts do not prevent such collection.

Where we know of no probative evidence to the contrary, we will presume that a producer relied on a misinterpretation of the regulations until such time as the producer filed a section 103 application for more than one proration unit in the same wellbore or for sales from any proration unit in any well which had previously obtained a

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regulations was filed by J-3 Oil Company, Inc. and assigned Docket No. RM81-24. While this rule was not initiated in response to that petition it resolves the issues raised there.

section 103 determination for a different proration unit, or made refunds as noted above. However, if a producer filed a section 103 application for more than one proration unit in the same wellbore or for sales from any proration unit in any wellbore different from the proration unit(s) which had obtained a section 103 determination, we can no longer presume that the producer continued to rely on a misinterpretation of the definition. In other words, refunds will be required and retroactive collections will not be permitted if the producer was aware of the filing requirement and simply made a late filing.[4]

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432; Administrative Procedure Act, 5 U.S.C. 553)

In consideration of the foregoing, the final regulation in § 271.303, of Part 271 of Subchapter H, Chapter I of Title 18, Code of Federal Regulations, is amended as set forth below. Because this amendment effects no substantive change, it is effective as of December 1, 1978.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,258]

46 F. R. 29699 (June 3, 1981)

18 CFR Part 271

[Docket No. RM79–76 (Colorado—5); Order No. 148]

High-Cost Gas Produced From Tight Formations

Issued: May 28, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR § 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts with modification the recommendation of the Colorado Oil and Gas Conservation Commission that the Lower Mesaverde Formation, consisting of the Rollings, Cozzette and Corcoran Sandstone members, be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective May 28, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8307, or Victor Zabel, (202) 357–8616.

SUPPLEMENTARY INFORMATION: The Commission hereby amends § 271.703(d) of its regulations to include the Lower Mesaverde Formation, consisting of the Rollins, Cozzette and Corcoran Sandstone members, in Colorado as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued October 27, 1980 (45 FR 72199, October 31, 1980)[1] based on a recommendation by the Colorado Oil and Gas Conservation Commission

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[4] An Appendix to this order provides several examples which provide further clarification of our policy concerning this issue.

[1] Comments on the proposed rule were invited and received. One commenter, on behalf of the State of California and the Public Utilities Commission of California, indicated that although it did not oppose the recommended designation, it was concerned that the existence of infill and other drilling programs evidenced the fact that the incentive price may not be necessary. The commenter stated that it would oppose incentives in such case. No party requested a public hearing in this matter and no hearing was held.

(Colorado) in accordance with § 271.703(c), that the Lower Mesaverde Formation be designated as a tight formation.

Evidence submitted by Colorado and the commenters supports Colorado's assertion that the Lower Mesaverde Formation meets the guidelines contained in § 271.703(c)(2). The Commission generally adopts the Colorado recommendation, with the modification discussed below.

Section 271.703(c)(2)(i)(D) of the Commission's regulations provides that in making recommendations for designations of tight formation areas to the Commission, a jurisdictional agency shall not include any formation or portion thereof,

> [if] the formation or any portion thereof was authorized to be developed by infill drilling prior to the date of recommendation, and the jurisdictional agency has information which in its judgment indicates that such formation or portion subject to infill drilling can be developed absent the incentive price established in paragraph (a) of this section * * *.

In reviewing Colorado's recommendation, the Commission found evidence indicating that certain areas within the recommended formation had been authorized to be developed by infill drilling prior to the date the recommendation was made, and that thirteen sections within the infill area had been substantially developed without the incentive price.[3] The Commission finds that these sections should be excluded from the designated tight formation.

In the thirteen sections which are being excluded from the tightformation designation, about 58% of the authorized maximum number of wells which can be drilled have been completed and are in production. Forty-six percent of the thirteen sections contain three or more wells on their 640-acre units. Sixty-two percent of these sections contain two or more wells. The Commission finds that such development clearly constitutes infill drilling as defined in § 271.703(b)(6) of the Commission's regulations. Since such drilling in these sections has occurred absent the incentive price, the Commission is excluding these sections from the tight formation designation under § 271.703(c)(2)(i)(D). Future consideration of these excluded areas for tight formation designation is not precluded by the Commission's action in this order, if sufficient information and economic data become available which indicates that this area would not be further developed without the tight formation incentive price.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, the incentive price should be made available as soon as possible. The need to make incentive prices available immediately established good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.;* Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432; Administrative Procedure Act, 5 U.S.C. 553)

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[3] Exhibit I of Colorado's submittal reveals that in Colorado Cause No. 166–1, issued April 17, 1962, 640-acre drilling units for gas production were established for portions of the Lower Mesaverde Formation. On April 18, 1967, by Order No. 166–8, Colorado, based upon a finding of lack of development and the need for additional gas, rescinded Order No. 166–1 for undeveloped units in the area. Thirteen sections which had been developed were not included in Order No. 166–8, and remained subject to Order No. 166–1.

On January 16, 1973, Colorado issued Order No. 166–11, which authorized additional drilling in the Lower Mesaverde Formation, with a maximum of four wells on a 640-acre unit in the thirteen sections that were not included in Order No. 166–8. The order also established new 160-acre units and incorporated the thirteen developed sections into the spaced area of the Plateau Field. The thirteen sections, which are being excluded from the recommendation as adopted by the Commission, are:

Township 10 South, Range 95 West, 6th P.M.,
Sections 17, 18, 19, and 30.
Township 10 South, Range 96 West, 6th P.M.,
Sections 12, 13, 23–28, and 33.

For the reasons stated herein, Part 271 of Subchapter I, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,259]

46 F. R. 29700 (June 3, 1981)

18 CFR Part 375

[Docket No. RM81-20; Order No. 147]

Delegation of the Commission's Authority to the Directors of Office of Electric Power Regulation, Office of the Chief Accountant, and Office of Pipeline and Producer Regulation

Issued: May 22, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: This rule delegates authority to take action on a variety of matters to the Chief Accountant, the Director of the Office of Electric Power Regulation, and the Office of Pipeline and Producer Regulation. This rule will serve to expedite the application process and will enable the Commission to focus its attention on more complicated and controversial tasks.

EFFECTIVE DATE: May 22, 1981.

FOR FURTHER INFORMATION CONTACT:
Peter Lefkin, Office of the General Counsel, 825 N. Capitol Street NE., Washington, D.C. 20426 (202) 357-8363.

SUPPLEMENTARY INFORMATION:

A. Background

On August 14, 1978, the Commission adopted Delegations of Authority [Phase I], Docket No. RM79-19, 43 FR 36433. That rule delegated to staff the responsibility for making certain decisions of a ministerial nature in order to free the Commission's time for issues of greater importance. By those delegations over 7000 decisions per year were transferred from the Commission to staff. On July 23, 1979, the Commission added to these delegations in a second delegation order [Phase II], Docket No. RM79-59, 44 FR 46449 (August 8, 1979). Subsequently, on February 13, 1981, additional delegations were made in Docket No. RM81-14, 46 FR 14119 (February 28, 1981) with respect to preliminary permits under the hydroelectric program. Most of these delegations are contained in Subpart C of Part 375.

As a continuation of this process, by this rule (Phase III) the Commission is delegating additional authority to the Directors of the Offices of Electric Power Regulation (OEPR), the Chief Accountant (OCA), and Pipeline and Producer Regulation (OPPR). In addition, several delegations previously made to the Secretary of the Commission contained in § 375.302 are being transferred to OPPR. The functions involved in the delegations from the Secretary have been delegated to other office directors in order to reduce the administrative burden on the Secretary.

Like the other delegation orders, Phase III is prompted by the Commission's determination that an inordinate amount of the Commission's time is spent on matters that do not require the attention of the Commission. These delegations will transfer to staff the responsibility of making a large number of these decisions and will enable the Commission to focus on more complicated and controversial tasks.

In general, the matters being delegated require only limited discretionary decision-making on the part of the office director. The delegation authority is qualified by the following two provisions. First, as a general rule, the director may only act on "uncontested" matters. "Uncontested" means, pursuant to 18 CFR 1.2(f)(23), that no petition for or notice of intervention in opposition to the application has been filed with the Commission under the Rules of Practice and Procedure. The receipt of an intervention in opposition to an application would result in the application being brought directly before the Commission. These definition of "uncontested" is deemed to include an application for a license or preliminary permit which competes with an application for an exemption from license, or an application for an exemption from license which competes with an application for a preliminary permit or license or exemption from license, or an application for a preliminary permit which competes with an application for a preliminary permit. In addition, it is deemed to include an application for preliminary permit which competes with an application for license and an application for license which competes with an application for preliminary permit.

Second, as is true of all other exercises of delegated authority, pursuant to 18 CFR § 1.7, any interested person may appeal the Director's decision to the Commission.

B. Summary

The delegation regulations contained in Subpart C of Part 375 are amended by this rule, as described below.

1. *Delegations to the Secretary.* Prior to this rule § 375.302(v) delegated to the Secretary authority to take action on any statements of eligibility Section 375.302(u) granted the Secretary authority to issue temporary certificates to independent producers pursuant to section 7 of the Natural Gas Act.

This rule revokes those delegations to the Secretary and redelegates them to the Director of OPPR. This transfer of authority will serve to reduce the administrative burden on the Secretary.

2. *Delegations to Chief Accountant.* The Chief Accountant's authority to approve applications for issuance of securities, delegated by § 375.303(e)(6), is amended to raise the threshold level from $15,000,000 to $30,000,000.

3. *Delegations to Office of Pipeline and Producer Regulation.* Section 375.307 contains the delegations to the Director of OPPR. Paragraph (a) contains generally the delegations regarding routine certification certificate amendments and abandonment authority matters. Paragraph (a) is amended in subparagraph (1) by raising the threshold level of the Director's authority to issue permanent certificates or amend certificates for the construction or operation of facilities from $1,000,000 to $5,000,000. Paragraph (a)(2) is amended to give the Director the authority to act on requests for waiver of single project or annual cost limits specified by § 157.7 (b)(1), (c), (d) and (g) relating to abbreviated applications for gas supply facilities. Paragraphs (a) (3), (4), and (5), as revised, considerably expand the Director's delegated power with respect to the certification of the transportation, storage and exchange of gas and the abandonment of facilities. Paragraph (a)(7) gives the Director authority to take action on blanket certificate applications by interstate pipelines and Hinshaw pipelines. Paragraph (a)(8) concerning the Director's authority to act upon applications for amendments to authorized gas-for-gas exchanges, has been deleted and the language granting such authorizations has been incorporated into new § 375.307(a)(5). Subparagraph (9) and (10) of paragraph (a) of § 375.307 have been renumbered to be subparagraphs (8) and (9) respectively.

A new paragraph (a)(10) has been added to provide the Director with authority to pass upon requests by applicants to change delivery points to existing sales customers, providing that sales volumes remain within the customer's total existing contract demand and certificate levels. New paragraph (a)(11) authorizes the Director to pass upon uncontested applications for authorization and applications for amendments to authorizations for new or additional service to right-of-way grantors. New paragraph (a)(12) delegates to the Director the authority to take action on requests for customer name changes. New paragraph (a)(13), delegates to the Director authority to pass upon applications for approval of customer rate schedule shifts.

It should be noted that the Commission has recently undertaken a comprehensive review of its certificate process, and has issued a Notice of Proposed Rulemaking in Docket No. RM81-19, 46 FR 16903 (March 16, 1981). If this rule is issued, it may eliminate the need for many of the delegations contained in paragraph (a), specifically those contained in subparagraphs (a)(1), (a)(2), (a)(3), (a)(4), (a)(5), (a)(10), (a)(11), and (a)(12) as amended by this rule. However, as long as these decisions are made on a case-by-case basis, the Commission believes that delegation of authority to the Director of the Office of Pipeline and Producer Regulation, will expedite the processing of a large number of cases. However, at the time that it takes final action in Docket No. RM81-19 the Commission intends to reexamine the need for such delegations.

Paragraph (b) of § 375.307 has been amended by delegating to the Director, in subparagraph (4), authority to accept rate filings of jurisdictional natural gas companies which involve replacement and rollover contracts, and in subparagraph (5), authority to accept statements of eligibility filed by producers of natural gas. The amendment to subparagraph (5) transfers to the Director of OPPR authority which was previously delegated to the Secretary, which delegation is also being revoked by this rule.

Paragraph (j) is amended to authorize the Director to deny or grant requests for a waiver of the 30 day statutory notice period, provided in section 4(d) of the Natural Gas Act. Under new paragraph (n) the Director may pass upon petitions by gas purchasers to permit one additional 60 day period of exemption for emergency sale arrangements, where the application for extension arrives at the Commission later than 45 days after the commencement of the initial period of exemption. Finally, the authority to initiate an annual survey of short term impacts of gas curtailments is granted by new paragraph (o).

4. *Delegations to Office of Electric Power Regulation.* The amendments to § 375.308 include additions to and modifications of the current delegation rules to the Director of OEPR concerning rate matters, licenses for hydropower projects, and other water resource matters.

Paragraph (p) is amended to expand in subparagraph (1) the Director's authority to reject for filing data and reports that are not in compliance with Commission opinions and orders.

Paragraph (w) is amended to expand the Director's authority to reject as well as accept amendments to agreements and rate schedules.

A new paragraph (ll) gives the Director authority to act on uncontested rates and rate schedules filed by the Secretary of Energy, or his designee for power developed at projects owned and operated by the Federal Government and for services provided by Federal power marketing agencies.

New paragraph (mm) gives the Director authority to determine payments for headwater benefits from the operation of Federal Reservoir projects. New paragraph (nn) authorizes the Director to take appropriate action on a Declaration of Intention filed pursuant to section 23 of the Federal Power Act.

New paragraph (oo) provides the Director with authority to pass upon materially comparable competing applications for preliminary permit and license for water projects that compete with applications for exemption from license, application for preliminary permit that compete with an application for license, application for exemption from license that compete with an application for preliminary permit, license, or exemption from license and application for license that compete with an application for preliminary permit.

The Commission delegates its authority to the Director under paragraph (oo) only insofar as the competing applications are uncontested. However, competing applications for authorization to study or develop a water power project routinely contest other applications for the same site by filing petitions for, or notices of intervention. In order to permit the Director to act in those usual cases where competing applicants contest one another's applications, the limitation in new paragraph (oo)(2) prohibits the Director from acting only where third parties have intervened to raise questions of fact or law about a competing application. In other words, for purposes of this delegation, a competing applicant will not be deemed a contestant so as to deprive the Director of the delegated authority to pass on the applications described in paragraph (oo)(1).

New paragraph (pp) gives the Director's authority to pass upon uncontested applications for certification of the qualifying status of cogenerators and small power producers under § 292.107(b) of the Commission's rules. Authority to take appropriate action on requests by any state regulatory authority or nonregulated utility to waive the requirements of Subpart C of Part 292 of the Commission regulations governing cogeneration and small power production facilities is set forth in new paragraph (qq).

C. Effective Date

The Commission waives the notice and comment provisions of the Administrative Procedure Act, 5 U.S.C. 553(b), because the rule is one of agency procedure and practice. Public procedure is therefore unnecessary. In addition, the Commission finds good cause to make the rule effective immediately, pursuant to 5 U.S.C. 553(d). The Commission currently faces the task of having to make hundreds of decisions on items which can fairly be classified as routine. This delegation will permit a more efficient discharge of the Commission's responsibilities, enabling the Commission to devote its attention to the more controversial issues before it, while insuring the public of quicker action on items of concern.

The Commission nevertheless invites interested members of the public to submit comments or suggestions regarding these regulations. The Commission and its staff will evaluate any information received from interested persons and will consider appropriate revisions to these regulations as a result of comments received. An original and 14 copies should be filed by June 21, 1981, with the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426. All comments should refer, on the cover page to Docket No. RM81-20.

(Federal Power Act, as amended, 16 U.S.C. 792 *et seq.*, Natural Gas Act, as amended, 15 U.S.C. 717 *et seq.*, Natural Gas Policy Act of 1978, 15 U.S.C. 3301 *et seq.*, Department of Energy Organization Act, 42 U.S.C. 7107 *et seq.*, E.O. 12009, 3 CFR 142 (1978))

In consideration of the foregoing, the Commission amends Subpart C, Part 375, Subchapter W of Chapter I, Title 18 of the *Code of Federal Regulations*, as provided below, effective on the date of issuance.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,260]

46 F. R. 30489 (June 9, 1981); 46 F. R. 36692 (July 15, 1981)

18 CFR Part 271

[Order No. 152; Docket No. RM79-76 (Colorado—7)]

High-Cost Gas Produced From Tight Formations; Final Rule

Issued: June 3, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions

which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR § 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Colorado Oil and Gas Conservation Commission that the Dakota Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective on June 3, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8616.

Order No. 152

Issued June 3, 1981.

Before Commissioners: Georgiana Sheldon, Acting Chairman; Matthew Holden, Jr. and J. David Hughes. In the matter of High-Cost Gas Produced From Tight Formations, Docket No. RM79-76 (Colorado—7).

The Commission hereby amends § 271.703(d) of its regulations to include the Dakota Formation in Colorado as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued November 19, 1980 (45 FR 78701, November 26, 1980)[1] based on a recommendation by the Colorado Oil and Gas Conservation Commission (Colorado) in accordance with § 271.703(c), that the Dakota Formation be designated as a tight formation.

Evidence submitted by Colorado and the commenters supports Colorado's assertion that the Dakota Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Colorado recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices be made available immediately. The need to make incentive prices available immediately established good cause to waive the thirty day publication period.

(Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. § 3301-3432; Administrative Procedure Act, 5 U.S.C. 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,261]

46 F. R. 30490 (June 9, 1981)

18 CFR Part 271

[Order No. 151; Docket No. RM79-76 (Colorado—9)]

High-Cost Gas Produced From Tight Formations; Final Rule

Issued June 3, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or

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[1] Comments were invited and favorable comments were received. No party requested a public hearing and no hearing was held.

costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR § 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Colorado Oil and Gas Conservation Commission that the Corcoran Formation and Cozzette Formation each be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective June 3, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8307, or Victor Zabel, (202) 357–8559.

Order No. 151

Issued June 3, 1981.

Before Commissioners: Georgiana Sheldon, Acting Chairman; Matthew Holden, Jr. and J. David Hughes. In the matter of High-Cost Gas Produced From Tight Formations, Docket No. RM79–76 (Colorado—9).

The Commission hereby amends § 271.703(d) of its regulations to include the Corcoran and Cozzette Formations in Colorado as designated tight formations eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued November 19, 1980 (45 FR 78703, November 28, 1980)[1] based on a recommendation by the Colorado Oil and Gas Conservation Commission (Colorado) in accordance with § 271.703(c), that the Corcoran and Cozzette Formations be designated as tight formations.

Evidence submitted by Colorado and the commenters supports Colorado's assertion that the Corcoran and Cozzette Formations meet the guidelines contained in § 271.703(c)(2). The Commission adopts the Colorado recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices be made available immediately. The need to make incentive prices available immediately establishes good cause to waive the thirty day publication period.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.;* Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432; Administrative Procedure Act, 5 U.S.C. 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,262]

46 F. R. 30491 (June 9, 1981); 46 F. R. 36692 (July 15, 1981)

18 CFR Part 271

[Order No. 150; Docket No. RM79–76 (Colorado—8)]

High-Cost Gas Produced From Tight Formations; Adoption of Designation Recommendation

Issued June 3, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain

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[1] Comments were invited and favorable comments were received. No party requested a public hearing and no hearing was held.

types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR § 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Colorado Oil and Gas Conservation Commission that the Sanastee Formation and Dakota Formation each be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective on June 3, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8559.

Order No. 150

Issued June 3, 1981.

Before Commissioners: Georgiana Sheldon, Acting Chairman; Matthew Holden, Jr. and J. David Hughes. In the matter of High-Cost Gas Produced From Tight Formations, Docket No. RM79-76 (Colorado—8).

The Commission hereby amends § 271.703(d) of its regulations to include the Sanastee and Dakota Formations in Colorado as designated tight formations eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued November 19, 1980 (45 FR 78703, November 26, 1980)[1] based on a recommendation by the Colorado Oil and Gas Conservation Commission (Colorado) in accordance with § 271.703(c), that the Sanastee and Dakota Formations be designated as tight formations.

Evidence submitted by Colorado and the commenters supports Colorado's assertion that the Sanastee and Dakota Formations meet the guidelines contained in § 271.703(c)(2). The Commission adopts the Colorado recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices be made available immediately. The need to make incentive prices available immediately establishes good cause to waive the thirty day publication period.

(Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. § 3301-3432; Administrative Procedure Act, 5 U.S.C. 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,263]

46 F. R. 30491 (June 9, 1981)

18 CFR Part 284

[Order No. 30-F; Docket No. RM79-34]

Transportation Certificates for Natural Gas for the Displacement of Fuel Oil

Issued May 21, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: On May 17, 1979, the Federal Energy Regulatory Commission

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[1] Comments were invited and favorable comments were received. No party requested a public hearing and no hearing was held.

(Commission) issued Order No. 30 in Docket No. RM79-34 (44 FR 30323; May 25, 1979). That order established a short-term program authorizing the transportation of natural gas for the displacement of fuel oil. The program, which was originally scheduled to terminate on June 1, 1980, was extended by Order No. 30-D (45 FR 56046; August 22, 1980) through May 31, 1981. By this rule, the Commission again extends the Order No. 30 program until 90 days after a final rule becomes effective in Docket No. RM81-19. A Notice of Proposed Rulemaking was issued in Docket No. RM81-19 on March 10, 1981 (46 FR 16903; March 16, 1981).[1] The Commission invites written comments in Docket No. RM81-19 on whether the pipeline transportation of end-user natural gas for the displacement of fuel oil (presently encompassed in the order No. 30 program) should be included in the final rule in Docket No. RM81-19.

DATES: Effective Date: May 31, 1981. Comments must be received in Docket No. RM81-19 on whether the pipeline transportation of end-user natural gas for the displacement of fuel oil should be included in the final rule in Docket No. RM81-19 on or before June 21, 1981.

ADDRESS: All comments regarding Docket No. RM81-19 to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Robert C. Platt, Assistant Advisory Counsel, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357-8457.

SUPPLEMENTARY INFORMATION: On March 10, 1981, Consolidated Edison Company of New York, Inc., National Gas and Oil Corporation, the Ohio Producers Group,[2] Public Service Electric and Gas Company, Salt River Project Agricultural Improvement and Power District, Long Island Lighting Company, Alabama-Tennessee Natural Gas Company, and Phelps Dodge Corporation (Petitioners) filed a petition in this Docket seeking a rulemaking pursuant to § 1.7 of the Commission's Rules of Practice and Procedure (18 CFR 1.7). Petitioners seeks an amendment of § 284.201(e) of the Commission's regulations to provide a temporary extension of the fuel oil displacement program promulgated in Order No. 30.[3] In addition, the Petitioners seek "a more effective program to replace Order No. 30," (petition at 5) which would embody eight design considerations.[4]

On May 17, 1979, the Commission issued Order No. 30 which established a short-term program authorizing the transportation of natural gas for the displacement of fuel oil. That order was adopted in response to a proposal of the Economic Regulatory Administration (ERA) of the Department of Energy which was referred to the Commission pursuant to Section 403(a) of the Department of Energy Organization Act, 42 U.S.C. 7173(a) (DOE Act).

In Order No. 30, the Commission authorized interstate pipelines to transport natural gas to end-users certified by the ERA.[5] In significant part, the Commission determined that the public interest was served by action to displace fuel oil with natural gas in order to relieve demand pressure on distillate and related stocks of petroleum products as the peak winter heating season approached. The

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[1] See FR Doc. 81-17007 in the Proposed Rule Section of this issue.

[2] The Ohio Producers Group consists of Leader Equities Inc., Clinton Oil Company, Jadoil, Inc., W. E. Shrider Company, Wilson Petroleum Coporation, Hopewell Oil and Gas Development Co., and Edco Drilling and Producing, Inc.

[3] Docket No. RM79-34, issued May 17, 1979, 44 FR 30323 (May 25, 1979).

[4] On May 12, 1981, the ERA referred a similar set of rulemaking design criteria to the Commission pursuant to Section 403 of the DOE Organization Act.

[5] In a related rule, the ERA established a procedure to certify the eligibility of end-users for this program. 10 CFR Part 595, 44 FR 20396 (April 5, 1979).

Commission perceived the fuel oil shortages would be relieved by the beginning of the next summer period. Hence, the rule originally terminated the program on June 1, 1980.

On August 15, 1980, the Commission issued Order No. 30-D,[6] which extended the program through May 31, 1981. In Order No. 30-D, the Commission noted:

> By [May 31, 1981], the Commission expects to implement more effective programs to dispose of excess natural gas deliverabilities. It is our objective to reassess current policies and programs and so develop a comprehensive long term policy prior to May 31, 1981.

Such a comprehensive reexamination of the Commission's transportation policies was initiated in Docket Nos. RM81-19 and RM81-29.[7] In these dockets, the Commission proposed to issue blanket certificates to cover a variety of routine transactions. However, it does not appear that the Commission will be able to complete its consideration of public comments and issue final rules in the RM81-19 and RM81-29 Dockets prior to May 31, 1981. In addition, transportation contemplated by those proposed rules cannot occur until the Commission processes applications for blanket certificates. Accordingly, the Commission is extending the duration of the Order No. 30 program until 90 days after a final rule becomes effective in Docket No. RM81-19. This interim extension is accomplished by amending the definition of "fuel shortage emergency period" in § 284.201(e).

Written Comments

The Commission invites interested persons, who have not already done so, to submit written comments in Docket No. RM81-19 on whether the pipeline transportation of end-user natural gas for the displacement of fuel oil (presently encompassed in the Order No. 30 program) should be included in the final rule in Docket No. RM81-19.

An original and 14 conformed copies of written comments should be filed by June 21, 1981. Comments should reference Docket No. RM81-19 and should be addressed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

Written comments will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426. The Commission will consider all timely comments before acting on this issue in Docket No. RM81-19.

Effective Date

In order to avoid disruption of ongoing transactions authorized under Order No. 30, this rule must take effect prior to June 1, 1981. For this reason, the Commission, in accordance with 5 U.S.C. §§ 553(b) and (d), finds that good cause exists to waive normal notice and effective date requirements. Accordingly, this rule is effective on May 31, 1981.

[Natural Gas Act, 15 U.S.C. § 717-717w; Natural Gas Policy Act of 1978, 15 U.S.C. § 3301-3432; Department of Energy Organization Act, 42 U.S.C. § 7101-7352; E.O. 12009, 42 FR 46267.]

In consideration of the foregoing, Part 284 of Chapter I, Title 18, Code of Federal Regulations, is amended as set forth, effective May 31, 1981.

By the Commission.

Kenneth F. Plumb,

Secretary.

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[6] Docket No. RM79-34, Order No. 30-D, issued on August 15, 1980, 12 FERC ¶ 61,166, 45 FR 56046 (August 22, 1980).

[7] Docket No. RM81-19, Notice of Proposed Rulemaking issued on March 10, 1981, 46 FR 16903 (March 16, 1981); Docket No. RM81-29, Notice of Proposed Rulemaking, issued on April 27, 1981, 46 FR 24585 (May 1, 1981).

[¶ 30,264]

46 F. R. 31253 (June 15, 1981); 46 F. R. 36691 (July 15, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Colorado—12); Order No. 156]

High-Cost Gas Produced From Tight Formations; Colorado; Recommendation of Areas for Designation as Tight Formations

Issued: June 10, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Colorado Oil and Gas Conservation Commission that the Corcoran and Cozzette Formations be designated as tight formations under § 271.703(d).

EFFECTIVE DATE: This rule is effective June 10, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8616.

SUPPLEMENTARY INFORMATION: The Commission hereby amends § 271.703(d) of its regulations to include the Corcoran and Cozzette Formations in Colorado as designated tight formations eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued February 4, 1981 (46 FR 11842, February 11, 1981)[1] based on a recommendation by the Colorado Oil and Gas Conservation Commission (Colorado) in accordance with § 271.703(c), that the Corcoran and Cozzette Formations be designated as tight formations.

Evidence submitted by Colorado and the commenters supports Colorado's assertion that the Corcoran and Cozzette Formations meet the guidelines contained in § 271.703(c)(2). The Commission adopts the Colorado recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices be made available immediately. The need to make incentive prices immediately available establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3432; Administrative Procedure Act, 5 U.S.C. 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective June 10, 1981.

By the Commission.

Kenneth F. Plumb,

Secretary.

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[1] Comments were invited and received. No party requested a public hearing and no hearing was held.

[¶ 30,265]

46 F. R. 31254 (June 15, 1981)

18 CFR Part 271

[Docket No. RM79-76 (New Mexico—3); Order No. 157]

High-Cost Gas Produced From Tight Formations; New Mexico; Recommendation of Areas for Designation as Tight Formations

Issued: June 10, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the New Mexico Oil Conservation Commission that the Abo Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective June 10, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8616.

SUPPLEMENTARY INFORMATION: The Commission hereby amends § 271.703(d) of its regulations to include the Abo Formation in New Mexico as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued March 27, 1981 (46 FR 20219, April 3, 1981)[1] based on a recommendation by the New Mexico Oil Conservation Division (New Mexico) in accordance with § 271.703(c), that the Abo Formation be designated as a tight formation.

Evidence submitted by New Mexico and the commenter supports New Mexico's assertion that the Abo Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the New Mexico recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices be made available immediately. The need to make incentive prices immediately available establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.;* Natural Gas Policy Act of 1978, 15 U.S.C. 3301—3432; Administrative Procedure Act, 5 U.S.C. 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, *Code of Federal Regulations,* is amended as set forth below, effective June 10, 1981.

By the Commission.

Kenneth F. Plumb,

Secretary.

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[1] Comments were invited and one was received. No party requested a public hearing and no hearing was held.

[¶ 30,266]

46 F. R. 31255 (June 15, 1981)

18 CFR Part 271

[Docket No. RM79-76 (New Mexico-4); Order No. 155]

High-Cost Gas Produced From Tight Formations; New Mexico; Recommendation of Areas for Designation as Tight Formations

Issued: June 10, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the New Mexico Oil Conservation Commission that the Fruitland Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective June 10, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8616.

SUPPLEMENTARY INFORMATION: The Commission hereby amends § 271.703(d) of its regulations to include the Fruitland Formation in New Mexico as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, NOPR, issued March 27, 1981 (46 FR 20218, April 3, 1981) [1] based on a recommendation by the New Mexico Oil Conservation Division (New Mexico) in accordance with § 271.703(c), that the Fruitland Formation be designated as a tight formation.

Evidence submitted by New Mexico and the commenters supports its assertion that the Fruitland Formation meet the guidelines contained in § 271.703(c)(2). The Commission adopts the New Mexico recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices be made available as soon as possible. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3432; Administrative Procedure Act, 5 U.S.C. 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective June 10, 1981.

By the Commission
Kenneth F. Plumb,
Secretary.

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[1] Comments were invited and were received. No party requested a public hearing and no hearing was held.

[¶ 30,267]

46 F. R. 31255 (June 15, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Texas-8); Order No. 153]

High-Cost Gas Produced From Tight Formations; Texas; Recommendation of Areas for Designation as Tight Formation

Issued June 10, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Railroad Commission of Texas that the Geopressured Wilcox Lobo Sandstone Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective June 10, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Walter Lawson, (202) 357-8556.

SUPPLEMENTARY INFORMATION: The Commission hereby amends § 271.703(d) of its regulations to include the Geopressured Wilcox Lobo Sandstone Formation in Texas as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued April 1, 1981 (46 FR 20684, April 7, 1981)[1] based on a recommendation by the Railroad Commission of Texas (Texas) in accordance with § 271.703(c), that the Geopressured Wilcox Lobo Sandstone Formation be designated as a tight formation.

Evidence submitted by Texas supports its assertion that the Geopressured Wilcox Lobo Sandstone Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Texas recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices be made available immediately. The need to make incentive prices available immediately establishes good cause to waive the thirty day publication period.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3432; Administrative Procedure Act, 5 U.S.C. 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective June 10, 1981.

By the Commission.

Kenneth F. Plumb,

Secretary.

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[1] Comments were invited and none were received. No party requested a public hearing and no hearing was held.

[¶ 30,268]

46 F. R. 31256 (June 15, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Texas—9); Order No. 154]

High-Cost Gas Produced From Tight Formations; Texas; Recommendation of Areas for Designation as Tight Formation

Issued: June 10, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Railroad Commission of Texas that the Travis Peak Formation in the Sym-Jac, West Field be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective June 10, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Walter Lawson, (202) 357-8556.

SUPPLEMENTARY INFORMATION: The Commission hereby amends § 271.703(d) of its regulations to include the Travis Peak Formation in the Sym-Jac, West (Hosston) Field in Texas as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued April 1, 1981 (46 FR 20685, April 7, 1981)[1] based on a recommendation by the Railroad Commission of Texas (Texas) in accordance with § 271.703(c), that the Travis Peak Formation in the Sym-Jac, West Field be designated as a tight formation.

Evidence submitted by Texas supports its assertion that the Travis Peak Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Texas recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices be made available immediately. The need to make incentive prices available immediately establishes good cause to waive the thirty day publication period.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3432; Administrative Procedure Act, 5 U.S.C. 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective June 10, 1981.

By the Commission.
Kenneth F. Plumb,
Secretary.

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[1] Comments were invited and none were received. No party requested a public hearing and no hearing was held.

[¶ 30,269]

46 F. R. 32237 (June 22, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Louisiana—4) (Order No. 159)]

High-Cost Gas Produced From Tight Formations; Final Rule

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the State of Louisiana Office of Conservation that the Gray Sand, Reservoir A be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective June 17, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Walter Lawson, (202) 357-8556.

SUPPLEMENTARY INFORMATION:

Order No. 159

Issued June 17, 1981.

In the matter of high-cost gas produced from tight formations; Docket No. RM79-76 (Louisiana—4).

The Commission hereby amends § 271.703(d) of its regulations to include the Gray Sand, Reservoir A in Louisiana as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued April 1, 1981 (46 FR 20686, April 7, 1981)[1] based on a recommendation by the State of Louisiana Office of Conservation (Louisiana), in accordance with § 271.703(c), that the Gray Sand, Reservoir A be designated as a tight formation.

Evidence submitted by Louisiana supports its assertion that the Gray Sand, Reservoir A meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Louisiana recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices be made available immediately. The need to make incentive prices immediately available establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3342; Administrative Procedure Act, 5 U.S.C. 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective June 17, 1981.

By the Commission.

Kenneth F. Plumb,
Secretary.

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[1] Comments were invited and none were received. No party requested a public hearing and no hearing was held.

[¶ 30,270]

46 F. R. 32238 (June 22, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Louisiana—3) (Order No. 158)]

High-Cost Gas Produced From Tight Formations; Final Rule

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR § 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Louisiana Office of Conservation that the Cotton Valley Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective June 17, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Walter Lawson, (202) 357-8556.

SUPPLEMENTARY INFORMATION:

Order No. 158

Issued June 17, 1981.

In the matter of high-cost gas produced from tight formations; Docket No. RM 79-76 (Louisiana—3).

The Commission hereby amends § 271.703(d) of its regulations to include the Cotton Valley Formation in Louisiana as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, February 11, 1981 (46 FR 12760, February 18, 1981)[1] based on a recommendation by the State of Louisiana Office of Conservation (Louisiana) in accordance with § 271.703(c), that the Cotton Valley Formation be designated as a tight formation.

Evidence submitted by Louisiana supports its assertion that the Cotton Valley Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Louisiana recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.;* Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3342; Administrative Procedure Act, 15 U.S.C. 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective June 17, 1981.

By the Commission.

Kenneth F. Plumb,
Secretary.

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[1] Comments were invited and none were received. No party requested a public hearing and no hearing was held.

[¶ 30,271]

46 F. R. 33023 (June 26, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Alabama—1); Order No. 161]

High-Cost Gas Produced from Tight Formations; Final Rule

Issued June 23, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR § 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the State Oil and Gas Board of Alabama that the Basal Pennsylvanian Sand Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective June 23, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Walter Lawson, (202) 357-8556.

The Commission hereby amends § 271.703(d) of its regulations to include the Basal Pennsylvanian Sand Formation in Alabama as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued April 9, 1981 (46 FR 22004, April 15, 1981) [1] based on a recommendation by the State Oil and Gas Board of Alabama (Alabama) in accordance with § 271.703(c), that the Basal Pennsylvanian Sand Formation be designated as a tight formation.

Evidence submitted by Alabama supports its assertion that the Basal Pennsylvanian Sand Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Alabama recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. § 3301-3342; Administrative Procedure Act, 5 U.S.C. 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective June 23, 1981.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,272]

46 F. R. 33024 (June 26, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Colorado—15); Order No. 160]

High-Cost Gas Produced From Tight Formations; Final Rule

Issued June 23, 1981.

AGENCY: Federal Energy Regulatory Commission.

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[1] Comments were invited on the proposed and none were received. No party requested a hearing in this matter, and no hearing was held.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Colorado Oil and Gas Conservation Commission that the Dakota Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective June 23, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8616

The Commission hereby amends § 271.703(d) of its regulations to include the Dakota Formation in Colorado as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by the Director, OPPR, on May 4, 1981 (46 FR 25644, May 8, 1981),[1] based on a recommendation by the Colorado Oil and Gas Conservation Commission (Colorado) that the Dakota Formation should be designated as a tight formation in accordance with § 271.703(c).

Evidence submitted by Colorado and the commenter supports Colorado's assertion that the Dakota Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Colorado recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301-3342; Administrative Procedure Act, 15 U.S.C. 553.)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective June 23, 1981.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,273]

46 F. R. 33024 (June 26, 1981)

18 CFR Part 271

[Docket No. RM79-76 (West Virginia—1); Order No. 162]

High-Cost Gas Produced from Tight Formations; Final Rule

Issued June 23, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation

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[1] Comments were invited on the proposed and one was received. No party requested a hearing in this matter, and no hearing was held.

designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR § 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the State of West Virginia Office of Oil and Gas that the Ravencliff, Injun-Squaw, Weir and Berea Formations be designated as tight formations under § 271.703(d).

EFFECTIVE DATE: This rule is effective June 23, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Walter Lawson, (202) 357-8556.

The Commission hereby amends § 271.703(d) of its regulations to include the Ravencliff, Injun-Squaw, Weir and Berea Formations in West Virginia as designated tight formations eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued March 9, 1981 (46 FR 16914, March 16, 1981)[1] based on a recommendation by the State of West Virginia Office of Oil and Gas (West Virginia) in accordance with § 271.703(c) that the Ravencliff, Injun-Squaw, Weir and Berea Formations be designated as tight formations.

Evidence submitted by West Virginia supports its assertion that these formations meet the guidelines contained in § 271.703(c)(2). The Commission adopts the West Virginia recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301-3342; Administrative Procedure Act, 5 U.S.C. § 553)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective June 23, 1981.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,274]

46 F. R. 33025 (June 26, 1981)

18 CFR Part 292

[Order No. 70-E; Docket No. RM79-54]

Small Power Production and Cogeneration

Issued June 18, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Amendment to final rule.

SUMMARY: The Federal Energy Regulatory Commission hereby amends the final rule issued in Docket No. 79-54 regarding qualification of small power production and cogeneration facilities. This amendment removes the interim exclusion from qualifying status for new diesel and dual-fuel cogeneration facilities presently contained in § 292.203 of the Commission's rules. Such facilities will be allowed to obtain qualifying status on a generic basis subject to the general requirements for qualification contained in Part 292 of the Commission's rules.

EFFECTIVE DATE: This rule becomes effective on or before July 27, 1981.

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[1] Comments on the proposed rule were invited and none were received. One party requested a public hearing in this matter and then withdrew the request.

FOR FURTHER INFORMATION CONTACT:

Glenn Berger, Office of the General
Counsel, Federal Energy Regulatory
Commission, 825 North Capitol Street,
N.E., Washington, D.C. 20426, (202)
357–8033;
or
Michael Kessler, Office of the General
Counsel, Federal Energy Regulatory
Commission, 825 North Capitol Street,
N.E., Washington, D.C. 20426, (202)
357–8033.

Issued June 18, 1981.

On March 13, 1980, the Federal Energy Regulatory Commission (Commission) issued a final rule in Docket No. RM79–54 (Final Rule).[1] The Final Rule established criteria and procedures whereby an owner or operator of a small power production or cogeneration facility could determine if the facility were eligible to obtain qualifying status. This amendment to the Final Rule removes the interim exclusion from qualifying status for new diesel and dual-fuel cogeneration facilities. Such facilities will be allowed to obtain qualifying status on a generic basis subject to the general requirements for qualification contained in § 292.203 of the Commission's rules.

I. Background

Qualifying status enables a facility to be exempted from regulation under certain provisions of the Federal Power Act (FPA),[2] from regulation under the Public Utility Holding Company Act of 1935 (PUHCA)[3] and from certain state law and regulation,[4] and allows certain facilities to obtain the "avoided cost" rate for power purchased by an electric utility.

During the initial rulemakings implementing sections 201 and 210 of PURPA, the Commission performed an Environmental Assessment (EA). The EA analyzed the market penetration and environmental effects of all the technologies expected to be encouraged by the Commission's rules. Based on data developed by the EA the Commission determined that only diesel and dual-fuel commercial cogenerators in the New York City area had the potential to cause environmentally significant effects.[5] Pending completion of a Final Environmental Impact Statement (FEIS) by the Commission, new diesel cogeneration facilities were excluded in the Final Rule from obtaining qualifying status.[6]

On May 15, 1980, the Commission issued an order on rehearing of the Final Rule.[7] In that order, the Commission, *inter alia,* amended § 292.203(c) of its rules to require that new dual-fuel cogeneration facilities obtain qualification only on a case-by-case basis pursuant to the procedures established in § 292.207(b) of the Commission's rules. The Commission stated that before it would permit a new dual-fuel cogeneration facility to qualify, it would consider the emission characteristics of the facility and the number of qualifying cogeneration facilities in the vicinity of the applicant.[8]

Interim Exclusion of Diesel and Dual-Fuel Cogeneration Facilities

The Commission prepared a Draft EIS which analyzed the potential environmental effects of all the technologies encouraged by PURPA. The Draft EIS was circulated for comment in June 1980.[9]

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[1] Order No. 70, "Final Rule Establishing Requirements and Procedures for a Determination of Qualifying Status for Small Power Production and Cogeneration Facilities", 45 FR 17959 (March 20, 1980).

[2] 16 U.S.C. 792 *et seq.*, 18 CFR § 292.601.

[3] 15 U.S.C. 79 *et seq.*, 18 CFR § 292.602(b).

[4] 18 CFR § 292.602(c).

[5] *See* Notice of No Significant Impact and Notice to Prepare Environmental Impact Statement, March 31, 1980, Docket No. RM79–54.

[6] 18 CFR § 292.203(c). A new diesel cogeneration facility is one which: (1) derives its useful power output from a diesel engine, and (2) the installation of which began on or after March 13, 1980. 45 FR 17959, 17964 (March 20, 1980).

[7] Order Granting in Part and Denying in Part Rehearing of Order Nos. 69 and 70, and Amending Regulations. 45 FR 33958 (May 21, 1980).

[8] 45 FR 33958, 33963 (May 21, 1980). *See* 18 CFR § 292.203(c)(3).

The comprehensive review in the DEIS of all technologies encouraged by PURPA and the Commission's rules was intended to give an overview of the entire cogeneration and small power production program and was not intended to imply that PURPA encouragement of these technologies required an EIS.

According to the EA, the only technology which had the potential to cause environmentally significant effects, and for which an EIS was required, was diesel and dual-fuel cogeneration. The EA also found that the only area of the country where this potential existed was in the New York City area. Based on the findings of the EA and Draft EIS, an FEIS was prepared for diesel and dual-fuel cogeneration in the Mid-Atlantic Region. The FEIS responded to the comments on the Draft EIS and further analyzed the environmental effects, including air quality impacts, of diesel and dual-fuel cogeneration facilities.

The FEIS found that an increased population of diesel and dual-fuel cogeneration facilities in an air regime may cause significant environmental effects on air quality in the near term.[10] The FEIS concluded, however, that sufficient authority presently exists at the national, state, and local levels to regulate the construction and manner of operation of such facilities. Moreover, the FEIS concluded that no significant effect on air quality will occur in the New York City area and that the operation of all cogeneration facilities projected for this area would not violate nitrogen dioxide standards and would not consume the available increment of nitrogen dioxide.[11]

The Commission believes that it is the ability congenerators have to avoid municipal taxes, and not the rates available to them under PURPA, which is the primary force behind the development of diesel and dual-fuel cogeneration in New York City. The Commission notes that a substantial portion of Consolidated Edison's retail rate is used to collect taxes for the City of New York. This situation creates an economic incentive for industrial and commercial establishments in New York City to generate their own electric energy and to drop from the Consolidated Edison system in order to avoid the tax payment component in Consolidated Edison's retail rate. While it is true that PURPA provides for nondiscriminatory back-up and supplementary rates for cogenerators, New York law also provides for such non-discriminatory treatment.[12]

II. Summary of Rule Amendment

A. Revocation of Interim Exclusion

Based on the findings and conclusions contained in the FEIS, the Commission is revoking the interim exclusion for both diesel and dual-fuel cogeneration facilities established in the Final Rule. Diesel and dual-fuel cogeneration facilities will be allowed to qualify on a generic basis, pursuant to § 292.207 of the Commission's rules.

The Commission believes it is appropriate to adopt the Proposed Action suggested in the FEIS, i.e., to qualify all diesel and dual-fuel cogeneration facilities that meet the criteria established pursuant to section 201 of PURPA.[13] Although environmental controls are already in place on the State and Federal level to protect the environment against any adverse effects of diesel and dual-fuel cogeneration, the Commission will assess the extent of the market penetration by these technologies. The assessment will identify the concentration of diesel and dual-fuel qualifying cogeneration facilities as well as the pace at which such facilities are seeking qualifying status. A compilation will be made available to national and regional offices of the Environmental Protection Agency and State and local air quality agencies as appropriate. The compilation will also be available to other agencies and the public.

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[9] Federal Energy Regulatory Commission, Draft Environmental Impact Statement, June, 1980, Docket Nos. RM79-54 and RM79-55.

[10] Federal Energy Regulatory Commission, Final Environmental Impact Statement, April, 1981, Docket Nos. RM79-54 and RM79-55 at I-7a.

[11] *Id.* See n. 17, *infra.*

[12] N.Y. Transportation Corporations Law § 12 (McKinney) (Com. Supp. 1980-81); N.Y. Public Service Law § 65 (McKinney) (1975 and Com. Supp. 1980-81).

[13] *See* FEIS at V-1a.

The Commission notes that the attainment of qualifying status by any cogeneration or small power production facility, including diesel or dual-fuel cogeneration facilities, is neither a license nor a permit to operate the facility. Qualifying status only entitles a facility to the rate for purchases and exemptions set out in section 210 of PURPA and the Commission's rules. A qualifying facility is not exempt from any applicable Federal, state or local environmental, siting or similar requirements.

B. Conversion of Utility Boilers to Coal in New York City

In response to the Notice of Proposed Rulemaking [14] (NOPR) preceding the issuance of the Final Rule [15] some commenters stated that allowing qualifying cogeneration facilities to use oil, particularly in diesel engines, will use up available air quality increments for nitrogen dioxide thereby preventing the conversion of large utility oil-fired boilers to coal.[16] This issue is uniquely important to future development of diesel cogeneration in New York City.

The Commission specifically notes that Consolidated Edison has undertaken substantial activity, both in terms of economic investment and seeking regulatory approval, to convert to coal its Ravenswood power plant, located in Queens Borough, New York. Consolidated Edison anticipates completing conversion as early as November 1982, but no later than March 1984. The Ravenswood facility is located in an Air Quality Control Region where the air quality is acceptable, but where the ambient level of certain criteria pollutants is approaching non-attainment.[17] Consolidated Edison has expressed concern to the Commission that blanket approval of diesel and dual-fuel cogeneration facilities in New York City may prevent reconversion of the Ravenswood facility. Consolidated Edison was primarily concerned that qualification of such facilities may have a significant air quality impact.

The FEIS found that the operation of all cogeneration facilities projected for the New York City area would not consume the available increment for nitrogen dioxide and, therefore, would not endanger the conversion to coal of the Ravenswood facility.[18] The Commission believes, however, that it is in the public interest to ensure that Consolidated Edison's Ravenswood facility be allowed to convert to coal. Through the program discussed previously, the Commission will track the market penetration of qualifying diesel and dual-fuel cogeneration facilities in the New York City area. If the market penetration of qualifying diesel or dual-fuel cogeneration facilities is greater than expected, and if the Commission determines Consolidated Edison's reconversion of the Ravenswood facility is threatened, the Commission may restrict qualification of diesel and dual-fuel cogeneration facilities in the New York City area in the future.

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[14] 44 FR 38872 (July 3, 1979).

[15] In the NOPR, the Commission proposed rules which would enable diesel and dual-fuel cogeneration facilities to obtain qualifying status. The Commission received comments, both written and oral, regarding this proposal. The Commission considered these comments in formulation of its Final Rule. Furthermore, all interested parties had an opportunity to comment on the Draft EIS which was prepared prior to the FEIS. The Commission, believes, therefore, that all interested persons have had adequate opportunity to comment on qualification of diesel and dual-fuel cogeneration facilities.

[16] 45 FR at 17983–84.

[17] Standards for acceptable air quality are required under Section 109 of the Clean Air Act, 42 U.S.C. 1857 *et seq.* These standards set an acceptable level for any criteria pollutant. Air quality control regions which meet the level are considered to be attainment areas. Regions which exceed the levels are designated non-attainment for that criteria pollutant. Areas which do not meet the standards must provide a means to overcome obstacles to meeting attainment status.

[18] FEIS at 1–7a.

III. Summary of the Rulemaking

This amendment to the final rule deletes paragraph (c) of § 292.203 of the Commission's rules in its entirety. Paragraph (c) provided an interim exclusion from qualifying status for all new diesel cogeneration facilities. New dual-fuel cogeneration facilities qualified only on a case-by-case basis.

The effect of this amendment is to allow diesel and dual-fuel cogeneration facilities to qualify on a generic basis, subject to the requirements of § 292.203 of the Commission's rules. A corresponding amendment is made to § 292.203(b)(1) of the Commission's rules.

The Commission notes that on May 19, 1980, Elizabethtown Gas Company filed a Petition for Review of Order No. 70 and of the Commission's Order on Rehearing of Orders Nos. 69 and 70 in the United States Court of Appeals for the District of Columbia Circuit. On June 30, 1980 the Commission filed with the Court the certificate of Record in Lieu of Record. Under section 313(b) of the Federal Power Act that Court has exclusive jurisdiction to modify those orders. Accordingly, this order is issued subject to the Court's permission.

IV. Effective Date

The amendment to the regulations promulgated in this are effective on or before July 27, 1981.

(Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 2601, *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. § 791 *et seq.*, Federal Power Act, as amended, 16 U.S.C. § 792 *et seq.*, Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.*, 12009, 3 CFR Part 142 (1978))

In consideration of the foregoing, the Commission amends Part 292 of Chapter I, Title 18, Code of Federal Regulations, as set forth below, effective 30 days after publication in the Federal Register.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,275]

46 F. R. 35082 (July 7, 1981)

18 CFR Part 274

[Order No. 163; Docket No. RM79-3]

Order Issuing Alternative Filing Requirements

Issued: July 2, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule. Order issuing alternative filing requirements.

SUMMARY: Pursuant to § 274.207 of the Commission's regulations, the Oklahoma Corporation Commission (Oklahoma) filed an application for approval of alternative filing requirements for well determination applications filed under section 103 of the Natural Gas Policy Act of 1978. The Commission hereby approves Oklahoma's proposed alternative filing requirements and amends § 274.208 to reflect this change.

DATE: This order is effective July 2, 1981.

FOR FURTHER INFORMATION CONTACT: William Bushey, (202) 357-8590, or Leslie Lawner, (202) 357-8307.

SUPPLEMENTARY INFORMATION:

Issued: July 2, 1981.

In the matter of Natural Gas Policy Act of 1978, Oklahoma Corporation Commission Application for Alternative Filing Requirements; order issuing alternative filing requirements, Docket No. RM79-3, Order No. 163.

I. Background

On February 25, 1981, the Oklahoma Corporation Commission (Oklahoma) filed an application with the Commission for approval of alternative filing requirements pursuant to § 274.207 of the Commission's regulations. Notice of the application was issued on April 2, 1981. One comment was received in response to the notice of the application from Home Petroleum Corporation, and the commenter supported the proposed alternative filing requirements.

II. Discussion

The alternative filing requirements proposed by Oklahoma would replace the requirements for wells drilled in Oklahoma that are currently found in § 274.204(f) of the Commission's regulations. Section 274.204(f) requires an applicant seeking a well eligibility determination under section 103 of the Natural Gas Policy Act of 1978 (NGPA) to submit geological evidence and engineering data regarding the subject well to demonstrate that the well, if it is an additional well in an existing proration unit, is necessary to effectively and efficiently drain a portion of the reservoir covered by the proration unit which cannot be effectively and efficiently drained by any existing well within the proration unit.

Oklahoma proposes to eliminate the need to submit geological evidence and engineering data for wells subject to an application to determine eligibility under NGPA section 103 if the well was drilled within a drilling unit established under Oklahoma statute, and Oklahoma has issued an increased density order for the unit, and the increased density order contains the finding that the additional well is necessary for effective and efficient drainage (the "finding of necessity").

In Oklahoma, where an increased density order containing a finding of necessity has been issued, it means that a hearing has already been held at which geological evidence and engineering data of the same nature as required in § 274.204(f) has been presented. Oklahoma asserts that in lieu of the technical evidence required in § 274.204(f), it would be sufficient for the applicant seeking the section 103 well eligibility determination to include a copy of the increased density order containing the finding of necessity. If the Commission or any interested party desires to review the record supporting the finding of necessity for any particular applicant, the tape of the testimony and the transcript, together with any demonstrative evidence that had been submitted, would be available from Oklahoma.

The alternative filing requirements proposed by Oklahoma would relieve operators of the burden of having to make repetitive detailed showings of geological and engineering data. It would also relieve Oklahoma of the task of having to request this information from each applicant and the applicant would not have to prepare additional papers for filing, which would effectively speed up the process by which an applicant would receive its well eligibility determination.

Finally, Oklahoma requests that the alternative filing requirements be made effective immediately for all section 103 well determinations which have not yet become final under Part 275 of the Commission's regulations as of the day before the issuance of the Commission's order approving the alternative filing requirements.

The Commission believes that the filing of the increased density order, where such order issued by Oklahoma contains a finding of necessity, is an appropriate alternative to the filing requirement contained in § 274.204(f). Section 271.305 of the Commission's regulations requires that the jurisdictional agency for purposes of NGPA section 103 must make an explicit finding with respect to any additional well in a proration unit, that such a well is necessary to effectively and efficiently drain a portion of the reservoir covered by the proration unit which cannot be so drained by any exisitng well in the proration unit. The finding must be based on appropriate geological and engineering data and § 271.305 provides that such data be included in the notice of determination submitted to the Commission. The Commission finds that Oklahoma's alternative filing requirements would satisfy the concern expressed by § 271.305 that additional wells drilled in existing proration units be found to be necessary wells prior to qualifying as new, onshore production wells under NGPA section 103. Additionally, the Commission finds that the alternative requirements eliminate unnecessary filings, thereby lessening the regulatory burden on the operators and Oklahoma.

III. Public Procedures and Effective Date

Notice of Oklahoma's proposal was issued on April 2, 1981. No party requested a hearing on the proposed alternative filing requirements and no hearing was held. In view of the comment filed which supported the proposal, and the preceding discussion, the Commission approves Oklahoma's alternative filing requirements, described above.

The Commission finds that since the alternative filing requirements remove significant administrative burdens from applicants seeking well determinations from Oklahoma under section 103 of the NGPA, good cause exists to waive § 274.207(d) of the Commission's regulations in order to make the alternative filing requirements effective immediately for all section 103 determinations which have not yet become final under § 275.202(d) of the Commission's regulations as of the day before the date of this issuance of this order.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.;* Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3342; Administrative Procedure Act, 5 U.S.C. 553)

In consideration of the foregoing, Part 274 of Subchapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective July 2, 1981.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,276]

46 F. R. 38681 (July 29, 1981)

18 CFR Part 154

[Docket No. RM78-23]

Regulations Implementing Procedures for Refund of Louisiana First Use Tax by Primary Pipelines

Issued: July 17, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Interim rule and request for comments.

SUMMARY: The Commission amends paragraph (h) of 18 CFR 154.38 relating to the recovery of Louisiana First Use Tax by interstate pipelines. Specifically, the rule amends the procedures described in paragraph (h)(3) which require interstate pipelines to refund, with interest, any Louisiana First Use Tax collected by them in the event the First Use Tax is found invalid. Refunds are now required because the Supreme Court, in a judgment issued on June 15, 1981, *Maryland, et al. v. Louisiana*, 49 U.S.L.W. 4709 (1981), enjoined the State of Louisiana from further collection of the Louisiana First Use Tax on natural gas and directed Louisiana to refund all revenues collected pursuant to the First Use Tax together with all interest earned on those revenues upon the maturity date of each security in which the revenues and interest have been invested.

These amendments are necessary to conform § 154.38(h)(3) to the Supreme Court's judgment and to provide complete and speedy flow-through to jurisdictional pipeline customers of their First Use Tax payments. It requires interstate pipelines which receive LFUT

fund refunds to pass those refunds in lump sum payment, by check, to their jurisdictional customers within certain time periods.

This rule contains provisions applicable to any pipeline which paid the First Use Tax directly to Louisiana ("primary pipeline"). A separate order will treat the interstate pipelines which will receive LFUT funds from other pipelines ("secondary pipelines").

DATES:

Effective Date: The interim rule is to be effective July 17, 1981, contingent upon approval by the Fifth Circuit Court of Appeals for leave to amend Order Nos. 10, 10–A, 10–B and 10–C.

Comments Date: Comments must be filed on or before August 12, 1981, and refer to Docket No. RM78–23. Submit an original and 14 copies.

ADDRESSES: Comments should be mailed to: Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

Fredrick L. Jaffe, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426 (202) 357–8363, or

Sherri L. Booye, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426 (202) 357–5378

SUPPLEMENTARY INFORMATION:

I. Introduction

By this rule the Federal Energy Regulatory Commission (Commission) amends paragraph (h) of 18 CFR 154.38(h), relating to the recovery of Louisiana First Use Tax by interstate pipelines. Specifically, the rule amends the procedures described in paragraph (h)(3) which require interstate pipelines to refund, with interest, any Louisiana First Use Tax collected by them in the event the First Use Tax is found invalid. Refunds are now required because the Supreme Court, in a judgment issued on June 15, 1981, *Maryland, et al.* v. *Louisiana,* 49 U.S.L.W. 4709 (1981), enjoined the State of Louisiana from further collection of the Louisiana First Use Tax on natural gas and directed Louisiana to refund all revenues collected pursuant to the First Use Tax together with all interest earned on those revenues upon the maturity date of each security in which the revenues and interest have been invested.[1] The first refund is to be made by Louisiana on July 15, 1981.

These amendments are necessary to conform § 154.38(h)(3) to the Supreme Court's judgment and to provide complete and speedy flow-through to jurisdictional pipeline customers of their First Use Tax payments. It requires interstate pipelines which receive LFUT fund refunds to pass those refunds in lump sum payment, by check, to their jurisdictional customers within certain time periods.

This rule contains provisions applicable to any pipeline which paid the First Use Tax directly to Louisiana ("primary pipeline"). A separate order will treat the interstate pipelines which will receive LFUT funds from other pipelines ("secondary pipeline").

II. Background

A. Louisiana First Use Tax

This Louisiana First Use Tax [2] was imposed, at a rate of 7 cents per thousand cubic feet ("Mcf"),[3] upon the first "use" [4] of certain natural gas within

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[1] Louisiana First Use Tax revenues collected by Louisiana and interest accrued thereon are hereinafter referred to as "LFUT funds."

[2] 1978 La. Sess. Law Serv. 482 (Act No. 294), La. Rev. Stat. Ann. §§ 47:1301–47:1307 (West 1979 Supp.). Hereinafter referred to as "First Use Tax."

[3] La. Rev. Stat. Ann. § 47:1303(B).

[4] The term "use" is defined broadly as "[1] the sale; [2] the transportation in [Louisiana] to the point of delivery at the inlet of any processing plant; [3] the transportation in [Louisiana] of unprocessed natural gas to the point of delivery at the inlet of any measurement or storage facility; [4] transfer of possession or relinquishment of control at a delivery point in [Louisiana]; [5] processing for the extraction of liquefiable component products or waste materials; [6] use in manufacturing; [7] treatment; or [8] other ascertainable action at a point within [Louisiana]. La. Rev. Stat. § 47:1302(8).

Louisiana. This tax principally affects natural gas entering Louisiana from the Outer Continental Shelf.[5]

B. Commission Orders

In Order Nos. 10, 10–A, 10–B, and 10–C,[6] the Commission established and refined procedures governing pipeline recovery of the First Use Tax. The primary purpose of each of these orders was to develop a mechanism which guaranteed that the customers of the pipelines would receive full refunds if the tax was found to be unconstitutional.[7]

The presently effective regulation, 18 CFR 154.38(h), provides that pipelines shall make full refunds plus interest within 60 days of the issuance of a final and nonappealable court order finding the First Use Tax invalid, or such other date established by Commission order. In light of the Supreme Court judgment discussed below, this interim rule modifies the 60-day refund provision, requiring pipelines to make refunds within certain time periods after the State of Louisiana disburses LFUT funds to the pipelines.

C. Supreme Court Opinion and Judgment

On May 26, 1981, the United States Supreme Court issued an opinion in *Maryland v. Louisiana* [8] finding the First Use Tax unconstitutional. The Supreme Court held that section 1303(C) of the First Use Tax violates the Supremacy Clause and that the entire First Use Tax is unconstitutional under the Commerce Clause of the U.S. Constitution.

On June 15, 1981, the Supreme Court issued a judgment in *Maryland v. Louisiana* [9] which enjoined Louisiana from further collection of the Louisiana First Use Tax and directed Louisiana to refund to the pipeline taxpayers within 30 days of the judgment all revenues collected pursuant to the First Use Tax, together with all interest earned thereon. At the request of the plaintiff states and the plaintiff-intervenors,[10] the Court further provided that the First Use Tax revenues which have been invested by Louisiana in interest bearing securities are to be refunded by Louisiana as each security matures, to avoid any interest penalty associated with premature termination of these securities. This staggered refund procedure will increase refunds to consumers by at least $17 million.

D. Commission Action Since the Supreme Court Judgment

In response to the Supreme Court's judgment which enjoined Louisiana from any further collection of the First Use Tax, the Commission issued an order on June 29, 1981, to terminate the collection of the First Use Tax by the pipelines from their customers.[11] The Commission order directed the twenty pipelines tracking the First Use Tax to cease collection of the tax from their customers, to terminate the tracking of the tax, and to file revised tariff rate sheets.

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[5] Natural gas is subject to the First Use Tax if it is not subject to any severance or production tax levied by Louisiana or any other state or territory of the United States or is not subject to any import tax or tariff levied by the United States on imports from foreign countries. La. Rev. Stat. § 47:1303(a).

Because almost every state, including Louisiana (La. Rev. Stat. §§ 47:631–47:646), imposes a severance or production tax on gas producted within the state, the First Use Tax only applies to gas not subject to state taxation. Such gas is produced from federal enclaves within a state, the federal portion of the Outer Continental Shelf (43 U.S.C. § 1331(a)(2)) or imported from a foreign country. This principal target of the tax is gas from the federal portion of the Outer Continental Shelf ("OCS gas") which enters Louisiana.

[6] 43 FR 45553 (October 3, 1978), 43 FR 60438 (December 28, 1978), 44 FR 13460 (March 12, 1979), 45 FR 29011 (May 1, 1980), petitions for review pending, *Tennessee Gas Pipeline Co., et al. v. FERC*, 5th Cir., Nos. 78–3616, *et al.*, and *Florida Gas Transmission Co. v. FERC*, 5th Cir., No. 79–1665.

[7] Throughout the Order No. 10 series, the Commission reiterated its belief that the First Use Tax was unconstitutional and from the very beginning the Commission directed the Commission's Solicitor to actively challenge the constitutionality of the tax.

[8] 49 U.S.L.W. 4562 (1981).

[9] 49 U.S.L.W. 4706 (1981).

[10] The United States and the Commission were plaintiff-intervenors.

[11] *Arkansas Louisiana Gas Company, et al.*, Docket Nos. TA81–2–31, *et al.* (Issued June 29, 1981).

On July 8, 1981, the primary pipelines submitted to the Commission a proposed agreement which establishes the procedures by which Louisiana will refund LFUT funds to the primary pipelines. This agreement provides the method for allocating LFUT funds among the primary pipelines and establishes the dates on which Louisiana will make refunds to the primary pipelines. The total amount that will be refunded on July 15, 1981, exceeds $228,500,000.00 and certificates of deposit in face amounts of $403,325,000.00 will mature, with interest, between July 20, 1981, and May 14, 1982. The agreement between the primary pipelines and the State of Louisiana provides that funds paid on July 15, 1981, will earn interest to July 14, 1981, and generally that Louisiana will pay the remaining refunds within two business days of the maturity of each remaining certificate of deposit.[12] On July 13, 1981, the Commission approved the settlement agreement which was signed by the pipelines on July 10, 1981.[13]

E. Proposed Stipulation Submitted by 15 Primary Pipelines

On July 10, 1981, several primary pipelines submitted to the Commission a proposed stipulation for resolution of litigation in *Tennessee Gas Pipeline, et al. v. FERC*, 5th Cir. Nos. 78-3816, *et al.*, and *Florida Gas Transmission Co. v. FERC*, 5th Cir. No. 79-1885. Proponents of the stipulation indicate that the plaintiff states in *Maryland v. Louisiana, supra*, concur in the stipulation.

Tennessee Gas Pipeline Co. v. FERC involves a challenge by certain interstate pipelines to Commission Order Nos. 10, *et al.*, which, as noted above, established a Louisiana First Use Tax rate tracker pending the outcome of litigation regarding the constitutionality of that tax. The taxpaying pipelines questioned, *inter alia*, the legality of the rule which requires them to refund all tracker revenues, plus interest at six percent, within 60 days of a final and nonappealable court decision holding the First Use Tax statute unconstitutional—regardless of whether the State of Louisiana had refunded any tax collections to the taxpaying pipelines within that 60-day period. The case has been briefed and argued before the United States Court of Appeals for the Fifth Circuit. *Florida Gas Transmission Co. v. FERC* involves the same issues as *Tennessee*. It has been held in abeyance, pending decision in the lead case.

The proposed stipulation would substitute special refund procedures for the primary pipelines. The proposed stipulation sets forth procedures that the primary pipelines must follow to flow through to their jurisdictional customers the jurisdictional portion of LFUT funds as such funds are received from Louisiana. The stipulation requires the pipelines to refund to their customers the initial refund received from Louisiana within 30 days of disbursement and any subsequent refund received within 25 days of disbursement. If the pipelines fail to make the initial refund within 15 days or subsequent refunds within 10 days of disbursement, then these pipelines must pay interest computed at the prime rate on the amount not refunded for any additional time beyond the 15 days or 10 days, respectively.

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[12] In addition to the July 15, 1981 refund date, Louisiana is required to disburse refunds to the primary pipelines on: July 22, 1981, August 19, 1981, September 16, 1981, October 21, 1981, November 18, 1981, December 16, 1981, March 17, 1982, April 21, 1982, and May 18, 1982.

[13] *Arkansas Louisiana Gas Company, et al.*, Docket Nos. TA81-2-31, *et al.*, "Order Approving Agreement" (Issued July 13, 1981).

The stipulation further provides that the pipelines may defer the flow through to their customers of any refund received from Louisiana that is under a threshold level[14] until they receive refunds which cumulatively exceed that amount. If that amount is not exceeded, the pipelines may defer the flow through until receipt of the last refund from Louisiana.

The proposed stipulation contains four other important provisions. First, it requires that the pipelines follow an allocation methodology for LFUT fund refunds which reflects the First Use Tax charges incurred by each pipeline customer.[15] Second, it requires that pipelines make refunds to their customers by check. Third, it provides for the termination of the First Use Tax deferred account surcharge with the balance in the account increasing or decreasing the pipelines' first LFUT fund refund. Finally, the stipulation requires the pipelines to make periodic reports to the Commission showing such information as: (1) the total amount of the refund received by each pipeline and the date of that refund (2) the total amount flowed through to each of its customers by customer and the date of the flow through, and (3) the methodology used to flow through refunds.

III. Policy Considerations

The constitutionality of the First Use Tax was questioned from the date of its enactment. Therefore, the Commission established uniform special procedures for the collection of the First Use Tax, subject to refund, and a requirement that the primary pipelines "keep accurate accounts of all amounts received under this paragraph, specifying when, by whom, and in whose behalf such amounts are paid."[16] While the interim rule alters the current regulation set up by Order No. 10–C,[17] it has the same basic goal as that of the Order 10 series—guaranteeing that the customers of the pipelines will receive prompt, full refunds of LFUT funds, according to the amounts they paid.

A. Need for a Special Uniform Refund Procedure

We continue to see the necessity for a uniform refund rule. Otherwise, pipelines would probably refund the LFUT funds in accordance with their existing tariffs. Generally, the tariff refund provisions provide that refunds should be made either through a credit to Account 191 or through a lump sum refund procedure for refund periods prior to January 1, 1980.[18] The Commission believes that the use of these tariff refund provisions for making LFUT fund refunds may not be adequate to assure that the refunds promptly flow back to those customers that have incurred the cost of the First Use Tax.

(1) *Allocation of LFUT Fund Refunds.* Tariffs which require lump sum refunds adopt various methods for allocating the refunds among customers. These tariffs, which are often the result of settlement agreements, may allocate refunds among customers differently than the way funds were collected when the First Use Tax was in effect. Tariff provisions which require refunds to be credited to Account 191 will likely allocate the refunds among customers in a manner different than they were collected simply because of changes in sales patterns over time. The interim rule

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[14] The threshold level is the lesser of $250,000 or one mill per Mcf (or Dkt) for the pipeline's total sales for the period during which the pipeline included charges relating to the First Use Tax in its sales rates.

[15] The stipulation provides that the LFUT fund refunds must be allocated among customers based on actual billings during the period that First Use Tax charges were made, if the billings are readily available. If the billings are not available, LFUT fund refunds must be allocated based upon billing determinants for that period.

[16] 18 CFR 154.38(h)(2).

[17] The refund procedures are found in 18 CFR 154.38(h)(3).

[18] As a result of the Commission incremental pricing regulations implementing Title II of the Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3341–3348, lump sum refund procedures have been established in many pipeline tariffs to provide special lump sum refunds to non-exempt customers subject to the program.

adopts a uniform allocation methodology which more accurately reflects First Use Tax charges incurred by each customer than the tariff provisions presently in effect.

(2) *Prompt Refunds.* Tariff refund provisions may not allow for prompt refunds.[19] Refund provisions which require crediting of the refund to Account 191 may take as long as six to eight months (although earning interest in accordance with 18 CFR 154.67(d)) before the refund actually appears as a reduction to a pipeline customers' rates, if at all. If the *customer* is an interstate pipeline whose own refund tariff provisions also require crediting to Account 191, the process may be repeated.

The tariff provisions which require lump sum refund procedures may also delay flow through of LFUT funds to the ultimate consumer. Under most lump sum refund procedures, pipelines are not required to make refunds for at least 30 days from the date of receipt or until some refund threshold level is reached. The delay could be significant if, for example, the LFUT funds have to pass through 3 or 4 interstate pipelines with lump sum tariff provisions before reaching the ultimate consumer. The ultimate consumer may have to wait at least three or four months before receiving any refunds and as explained below, earn no interest during this delay. Since both existing tariff refund provisions—crediting of Account 191 and lump sum—do not expeditiously flow back refunds to consumers in a uniform manner, a special refund procedure is warranted.

(3) *Variation in Interest Requirements.* Finally, the significant variations in the interest requirements of the tariff refund provisions warrant adoption of a uniform interest requirement.[20] Some tariff refund provisions require that interest accrue from date of receipt; [21] others provide that no interest accures until forty-five days after receipt.[22] On refunds credited to Account 191, the tariff provisions often require, in accordance with the Commission's regulations,[23] that interest be computed on the month-ending balance in Account 191. This means that the interest requirement will vary from one refund to the next depending on what day the refund is received by the pipeline. A uniform refund procedure would require the same obligations from all pipelines and give the same protections to all customers, eliminating the inequity that a tariff approach would create.

For these reasons, the Commission does not believe it would be in the public interest to flow through LFUT fund refunds in accordance with each pipeline's tariff refund provision. The interim rule will serve to allocate more accurately the LFUT funds among customers who paid it, minimize the time period over which the refund must be made, and standardize the interest obligations of all pipelines. To the extent existing pipeline tariff refund provisions are inconsistent with this rule, the provisions of this interim rule shall apply.

B. Modification of the Primary Pipelines' Proposed Stipulation

The interim rule for the primary pipelines relies heavily on the proposed stipulation tendered to the Commission's Office of the Solicitor by fifteen of the primary pipelines as a proposed settlement of litigation in the U.S. Court of Appeals for the Fifth Circuit.[24]

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[19] The tariff provisions are appropriate when a single supplier refund is involved for a particular pipeline. However, the LFUT refunds will be made on ten different dates over the next year by many interstate pipelines.

[20] The tariff provisions vary because they incorporate provisions of older settlement agreements.

[21] *See e.g.* National Fuel Gas Supply Corporation. First Revised Sheet No. 36C to FERC Gas Tariff Original Volume No. 1: Paragraph 4.3 "*Carrying Charges on Supplier Refunds.*"

[22] *See e.g.* Cities Service Gas Company Second Substitute First Revised Sheet No. 64 to FERC Gas Tariff Original Volume No. 1: Paragraph 21.41 "*Gas Suplies Refunds Subject to Flow Through.*"

[23] 18 CFR 154.38(d)(4)(iv)(c).

[24] *See* Section II. E. *supra*, for a summary of the litigation and the stipulation.

The Commission chooses to codify the proposed stipulation as a interim rule instead of approving it as a settlement of the ongoing litigation for three practical reasons. First, not all twenty primary pipelines have agreed to enter into the stipulation.[25] Therefore, an interim rule is required for the remaining primary pipelines. Second, the Commission believes that persons affected by the proposed stipulation, not parties to the proposed stipulation, should have an opportunity to comment on the refund procedures we establish.[26] Execution of opportunity. Finally, the Commission believes that four minor substantive changes to the stipulation are warranted.

The first change modifies the stipulation's interest rate for LFUT funds in the pipelines' possession from the "current Citibank (N.A.) prime rate" to the interest rate in § 154.67(d) of the Commission's regulations, consistent with general Commission policy. It is a minor change to the interest rate requirement set forth in the stipulation, because the Commission's interest rate is based upon a three month average of the prime interest rate. However, it would eliminate any controversy over the term "current Citibank (N.A.) prime rate." The second change made by the rule to the stipulation is to modify the threshold level necessary before a primary pipeline is required to make a refund. The proposed stipulation may impose an unreasonable burden on certain interstate pipelines by requiring LFUT fund refunds if a pipeline receives the "lesser of $250,000 or one mill per Mcf (or Dkt) for the pipeline's total sales for the period during which the pipeline included charges relating to the First Use Tax in its sales rates pursuant to its Louisiana First Use Tax tariff provision." This provision could create an administrative burden for the interstate pipelines which in some cases may require the writing of refund checks for less than one dollar. To alleviate such an administrative burden and still protect the ultimate consumer, the interim rule requires refunds to be made if the pipeline receives LFUT funds which are "the greater of $250,000 or one fourth mill per Mcf (or Dkt) for the pipeline's total sales during the period April 1, 1979 to April 30, 1981." The third change clarifies the definition of "jurisdictional portion" in the allocation methodology by specifying that the jurisdictional portion must be computed on volumes "subject to First Use Tax charges." The fourth change requires the primary pipelines to file a schedule indicating amounts collected under the First Use Tax Tracker.

In all other respects, the Commission in the interim rule adopts the substantive procedures for primary pipelines set forth in the proposed stipulation and finds such procedures to be fair and equitable, and not unduly burdensome.

IV. Summary of the Rule

(1) *Method of Allocation.* The interim rule requires that all LFUT fund refunds made by primary pipelines be flowed through in lump sum payments by check to jurisdictional pipeline customers. The interim rule establishes an allocation methodology for LFUT fund refunds which reflects the First Use Tax charges incurred by each pipeline customer. Basically it requires the pipelines to allocate the refunds based upon the sales volumes of each customer subject to First Use Tax charges. The rule allows the primary pipelines to use a different methodology if it is based upon accurate records which the pipeline has kept.

(2) *Time Period for Making Refunds and Interest Provisions.* In the interim rule, the Commission requires the twenty primary pipelines which receive LFUT funds from Louisiana to make lump sum refunds within a specified time period after disbursement of the

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[25] There are five primary pipelines which have not yet concurred in the proposed stipulation: Panhandle Eastern Pipe Line Co., Trunkline Gas Co., El Paso Natural Gas Co., Arkansas Louisiana Gas Co., and Mid-Louisiana Gas Co.

[26] The comment procedures are set forth in IV., *infra.*

funds by Louisiana.[27] The rule requires these pipelines to make their first refund by August 14, 1981, on all LFUT funds disbursed by Louisiana to that pipeline on July 15, 1981. If the pipelines fail to make such refund by July 30, 1981, the rule provides that interest will be computed on the refund pursuant to § 154.67(d) of the Commission's regulations[28] from July 30, 1981, to the date the refund is disbursed to the pipelines' customers.

For each LFUT fund refund disbursed by Louisiana to the primary pipelines after July 15, 1981, the rule requires the pipelines to make refunds within 25 days of such disbursement. The primary pipelines are not required to pay any interest on refunds made within 10 days of the date Louisiana is required to disburse refunds to the pipelines. However, if refunds are not made within that 10 day period, the pipelines are required to pay interest in accordance with § 154.67(d) on these refunds from the 10th day after the date of disbursement by Louisiana to the date the refund is disbursed to the pipelines' customers.

The interim rule also requires, as of a specified date, the primary pipelines to stop collecting amounts necessary to amortize the balance in its First Use Tax Deferred Account and to add to or offset the next refund by the balance in that account. The rule further requires that the primary pipelines refund to each customer by check all payments still retained by the pipelines relating to the current First Use Rate Adjustment for the period on and after May 1, 1981.

Finally, the refund requirements for primary pipelines are subject to certain threshold triggers, with interest accruing after the primary 10 or 15 day period, in accordance with the proposed stipulation.

(4) *Refund Reports—Pipeline Compliance With Commission's Regulations.* In implementing the LFUT refund procedures, the Commission finds that there must be some mechanism by which it can assure that First Use Tax refunds are being made in compliance with its procedures. The interim rule requires them to make periodic reports to the Commission which show the following:

(1) The date of refund;

(2) The total amount of the refund received by the pipeline;

(3) The amount flowed through to each of its jurisdictional customers by customer;

(4) The date of each such flow through;

(5) The ratio used to determine the flow through for each of its jurisdictional customers and the basis on which that ratio was determined; and

(6) The amounts collected under the First Use Tracker.

IV. Effective Date and Comment Procedure

The interim regulations established by this rule are effective immediately, contingent upon leave of the United States Court of Appeals for the Fifth Circuit to amend the Commission's regulations regarding the primary pipelines. We shall direct our Solicitor to seek judicial authorization, as necessary.[29]

Publication of a proposed rulemaking for notice and public comment thereon and publication 30 days prior to the effective date of the rule have been omitted for good cause in accordance with section 553 of the Administrative

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[27] In accordance with an agreement signed by the pipelines on July 10, 1981 and approved by the Commission on July 13, 1981, *Arkansas Louisiana Gas Company, et al.*, "Order Approving Agreement," Docket Nos. TA81-2-31 *et al.* Louisiana is required to make refunds to the twenty primary pipelines on the following dates: July 15, 1981, July 22, 1981, August 19, 1981, September 16, 1981, October 21, 1981, November 18, 1981, December 16, 1981, March 17, 1982, April 21, 1982, and May 18, 1982.

[28] The interest rate in § 154.67(d) is based upon a three month average of the prime interest rate.

[29] As noted above, Order Nos. 10, 10-A, 10-B, and 10-C are presently under court review in *Tennessee Gas Pipeline Co., et al. v. FERC*, No. 78-3816 (5th Cir.). Under Section 19(b) of the Natural Gas Act, 15 U.S.C. 717r(b), the Fifth Circuit Court of Appeals presently has exclusive jurisdiction to affirm, modify, or set aside the Order No. 10 series. Therefore, the Commission must receive court approval before it can amend these orders.

Procedure Act, 5 U.S.C. 553 because delay in implementing the rule would be contrary to the public interest. The Supreme Court's judgment in *Maryland v. Louisiana, supra,* requires the State of Louisiana to refund a large portion of the LFUT funds by July 15, 1981. Unless the rule is effective immediately upon issuance (subject to permission of the Fifth Circuit) primary pipelines will, under current regulations, have to make refunds by August 14, 1981 (within 60 days of the Supreme Court judgment) of all amounts paid by them to Louisiana even though they will be receiving less from Louisiana by that date. Therefore, these new refund procedures must be immediately put into place so that interstate pipelines, distributors and state commissions can effectively flow through the refunds to the ultimate consumers.

Comments will be accepted on the interim rule and amendments to the rule will be considered with particular emphasis on any prospective refunds. Unless comments present compelling reasons to change provisions as to refunds made prior to issuance of the final rule, the Commission will not be inclined to impose any amendments retroactively.

Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. Each person submitting a comment should include his name and address and identify Docket No. RM78-23, and give reasons for any recommendations. An original and 14 copies should be filed with the Secretary of the Commission. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol N.E., Washington, D.C. 20426, during regular business hours. All comments should be received by the Commission by August 12, 1981.

Upon review of the comments, the Commission will consider whether public hearings are warranted.

(Natural Gas Act, 15 U.S.C. 717 *et seq.;* Department of Energy Organization Act, 42 U.S.C. 1701 *et seq.;* Administrative Procedure Act, 5 U.S.C. 553 *et seq.*)

In consideration of the foregoing § 154.38(h), Part 154 of Title 18, Code of Federal Regulations, is amended as set forth below, to become effective immediately, contingent upon approval by the Fifth Circuit Court of Appeals for leave to amend Order Nos. 10, 10–A, 10–B, and 10–C. Once judicial authorization to issue Order No. 10–D has been obtained, Order Nos. 10, 10–A, 10–B and 10–C, and the regulations adopted thereby, shall be deemed vacated as moot and the provisions thereof shall have no further effect, to the extent they are inconsistent with Order No. 10–D.[30]

By the Commission, Commissioner Hughes dissented with a separate statement attached. Chairman Butler concurred with a separate statement attached.

Kenneth F. Plumb,

Secretary.

Hughes, Commissioner, Dissenting:

This order allows a group of 20 primary pipelines 15 days interest free use of over a quarter billion dollars which belong to their customers.[1] By any conservative interest calculation, this amounts to at least two million dollars. At today's interest rates, even one day's interest free use of this amount could pay several Commissioners' salaries for a year.

The Commission issued Order No. 10 to deal with the Louisiana First Use Tax ("LFUT") while the constitutionality was being challenged. In accordance with the order, the pipelines collected the estimated LFUT from their customers and paid it to Louisiana. The purpose of the order was to ensure full and prompt refund of the monies to the consumers.

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[30] Since the primary pipelines will now be directed to make refunds to their customers only as LFUT fund refunds are received from the State of Louisiana, we believe that all issues are now moot in *Tennessee Gas Pipeline Co., et al.* v. *FERC,* 5th Cir. Nos. 78-3816, *et al.,* and *Florida Gas Transmission Co.* v. *FERC,* 5th Cir. No. 79-1865. We shall instruct our Solicitor to so inform the Court.

[1] In Order —— the secondary pipelines are allowed 15 days interest free use of the refund money. Although the time period and thus the profit involved are smaller, I object to that decision for the same reasons stated in this dissent.

The Supreme Court held that the Louisiana First Use Tax was unconstitutional. *Maryland, et al. v. Louisiana.* 49 U.S.L.W. 4562 (May 26, 1981). On June 15, 1981, the Court issued its decree which enjoined further collection of the tax and directed refund of all revenues collected together with all interest earned thereon by the State of Louisiana.

In summary, the Commission, in Order No. 10, and the Supreme Court have provided for return of the monies to the consumers who paid the tax initially. Neither Order No. 10 nor the Supreme Court decree anticipated a profit through interest income to Louisiana or the pipelines.

Therefore this order is inconsistent with the previous Order No. 10 and the Supreme Court decree in so far as it allows the pipelines interest free use of the refund money. The Order allows the pipelines 15 days carte blanche use of the money disbursed by Louisiana on July 15. On subsequent disbursements, the pipelines have 10 days interest free use of the money. This issue is largely one of unknown origin to the Commission since we did not participate in the litigation or the settlement discussions. We therefore did not have the benefit of participation in the give and take of negotiation nor the data necessary for the assessment of impact of this flow-through issue.

No one has demonstrated the administrative costs of tracking the interest earned, but given contemporary commercial practices replete with computerized data processing capabilities, such cost, it would appear, could be quickly ascertained. Thus, to the extent the decision might be justified on the basis of administrative burden, it would fail for lack of supporting data.

Others may question the proper method to measure the interest earned. I do not doubt that the return on the money may vary from pipeline to pipeline. Nonetheless, actual interest received could be revealed with disclosure of such actual interest not being an insurmountable obstacle; the labor involved is no justification for allowing for the interest free use of funds.

In any event, were the Commission to find that the pipelines did incur costs associated with the refund, there are a number of measures available to offset the interest income by such expenses. No attempt has been made to make such an adjustment. The result could lead to a serious unfairness to customers which I now hope the Court will address.

J. David Hughes,
Commissioner.

Butler, Chairman, Concurring Specially

These concurring views are intended to express my perspective of Commissioner Hughes' dissent. He has raised a concern in connection with the interim order that I share. There is no doubt that the interstate natural gas pipeline companies are sophisticated in the exercise of modern cash management practices, and that the exercise of those practices in the times during which the pipelines will hold the substantial sums of money to be refunded could—and undoubtedly will in some cases at least—result in not insubstantial interest to several pipelines.

A review of the approximated amounts of interest illustrates my difficulty with the dissent. Essentially, that difficulty is that the dissent offers an explication of a problem, but does not offer a solution. It leaves open the following questions, for example: Clearly, some pipelines will make substantial interest (*e.g., Tennessee*), but the interest to others will be negligible (*e.g., Mississippi River*). Do we require *all* to refund actual interest, or do we treat pipelines differently by considering the amounts of refunds in some, but not all, cases to be *de minimis*? If so, what is the standard? If we require all pipelines to refund all interest, have we not encouraged the pipelines to waste the time value of the money by *avoiding* the deposit of the funds in interest-bearing accounts in order to avoid the administrative hassle of making *de minimis* refunds? Would compensation of the pipelines for not wasting the time value of the money include reimbursement of out-of-pocket costs plus an "incentive" profit of some kind, or just the costs?

The problem with the dissent is that it is a statement of principle with which no one on the Commission could disagree, but it fails utterly to offer solutions to the problems that it raises itself. This may be inevitable because my colleague did not have the time to fashion a solution, but his difficulty is our difficulty. Neither did we. Offsetting the apparent inequity to the consumer, however, are several considerations. First, the Commission staff was not privy to the settlement negotiations, so we do not have any way of knowing what might have been traded among the pipelines and the states for this advantage to the pipelines. Secondly, the states represent their gas consumers, as well as the Commission. Indeed, that was the point of the lawsuit in the first place, and I for one am disinclined to suggest that the states have not done a good job of protecting the consumers resident therein. Finally, our Order No. 10-C would have allowed the refunds to be made in 30 days, and that time is substantially shortened by the agreement and thus by our interim order. That suggests to me that the states did not ignore its consumers, nor has the Commission, as the dissent implies. For these reasons, I believe the Commission has chosen the appropriate course of action under the circumstances in its interim order.

C. M. Butler III,

[¶ 30,277]

46 F. R. 38687 (July 29, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Colorado-10)]

Colorado; High-Cost Gas Produced From Tight Formations

July 24, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Colorado Oil and Gas Conservation Commission that the Morrow Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective July 24, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8616.

SUPPLEMENTARY INFORMATION:

The Commission hereby amends § 271.703(d) of its regulations to include the Morrow Formation in Kiowa County, Colorado as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued February 4, 1981 (46 FR 11841, February 11, 1981) [1] based on a recommendation by the Colorado Oil and Gas Conservation Commission (Colorado), in accordance with § 271.703(c), that the Morrow Formation be designated as a tight formation.

Colorado filed the recommenation under the alternative procedure specified in § 271.703(c)(2)(ii). This alternative procedure applies to formations which meet the stabilized production rate guideline (§ 271.703(c)(2)(i)(B)), and the crude oil production guideline (§ 271.703(c)(2)(i)(C)), but do not meet the permeability standard set forth in § 271.703(c)(2)(i)(A). As in this instance, the formation may be approved as a tight formation if the jurisdictional agency makes an adequate showing that the recommended formation exhibits low permeability characteristics and that the incentive price set in § 271.703(a) is necessary to provide reasonable incentives for production of natural gas from the formation due to the extraordinary costs associated with such production.

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[1] Comments on the proposed rule were invited and favorable comments were received. No party requested a public hearing and no hearing was held.

Colorado's submission contained extensive geological data which, upon analysis, demonstrated that the recommended formation exhibits low permeability charcteristics. Such data included information on the composition of the recommended formation, as well as the drilling history of the formation. Specific engineering data from one well was also presented as an example of low permeability encountered in the formation.

Colorado submitted, in addition to the technical data addressing permeability, information and analyses of an economic nature to establish the fact that the tight formation incentive price is necessary to provide reasonable incentives for the production of gas from the recommended formation.

The Commission has reviewed the Colorado submission, and believes that Colorado has demonstrated both the low permeability characteristics of the recommended formation and the fact that the price established for natural gas produced from tight formations is necessary to provide reasonable incentives for production of the natural gas from the recommended formation due to the extraordinary costs associated with such production.

The Commission finds that the evidence submitted by Colorado and the commenters supports Colorado's assertion that the Morrow Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Colorado recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available as soon as possible establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, (42 U.S.C. 7101 *et seq.*), Natural Gas Policy Act of 1978, (15 U.S.C. 3301–3432); Administrative Procedure Act, (5 U.S.C. 553))

For the reasons stated herein, Part 271 of Subchapter I, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective July 24, 1981.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,278]

46 F. R. 38688 (July 29, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Utah—1)]

Utah; High-Cost Gas Produced From Tight Formations

July 24, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Utah Board of Oil, Gas and Mining that the Wasatch/Mesaverde Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective July 24, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8307, or Victor Zabel, (202) 357–8616.

SUPPLEMENTARY INFORMATION: The Commission hereby amends § 271.703(d) of its regulations to include the Wasatch/Mesaverde Formation in Utah as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued May 18, 1981 (46 FR 27965, May 22, 1981)[1] based on a recommendation by the Utah Board of Oil, Gas and Mining (Utah) that the Wasatch/Mesaverde Formation should be designated as a tight formation in accordance with § 271.703(c).

Evidence submitted by Utah supports its assertion that the Wasatch/Mesaverde Formation meets the guidelines contained in § 271.703(c)(2).

The Commission adopts the Utah recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act (42 U.S.C. 7101 *et seq.*); Natural Gas Policy Act of 1978 (15 U.S.C. 3301–3342); Administrative Procedure Act (5 U.S.C. 553))

For the reasons stated herein, Part 271 of Subchapter I, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective July 24, 1981.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,279]

46 F. R. 38688 (July 29, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Wyoming—4)]

Wyoming; High-Cost Gas Produced From Tight Formations

July 24, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Wyoming Oil and Gas Conservation Commission that the Fox Hills Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective July 24, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8616.

SUPPLEMENTARY INFORMATION: The Commission hereby amends § 271.703(d) of its regulations to include the Fox Hills

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[1] Comments were invited and one favorable comment was received. No party requested a public hearing in this matter, and no hearing was held.

Formation in Wyoming as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by the Director, OPPR, on May 18, 1981 (46 FR 27966, May 22, 1981),[1] based on a recommendation by the Wyoming Oil and Gas Conservation Commission (Wyoming) that the Fox Hills Formation should be desingated as a tight formation in accordance with § 271.703(c).

Evidence submitted by Wyoming supports its assertion that the Fox Hills Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Wyoming recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act (42 U.S.C. 7101 *et seq.*); Natural Gas Policy Act of 1978 (15 U.S.C. 3301–3342); Administrative Procedure Act (15 U.S.C. 553))

For the reasons stated herein, Part 271 of Subchapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective July 24, 1981.

By the Commission.
Kenneth F. Plumb,
Secretary.

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[1] Comments were invited and none were received. No party requested a hearing in this matter, and no hearing was held.

[¶ 30,280]

46 F. R. 38906 (July 30, 1981)

18 CFR Part 154

[Docket No. RM81-37]

Regulations Implementing Procedures for Refund of Louisiana First Use Tax by Secondary Pipelines

Issued July 22, 1981.

AGENCY: Federal Energy Regulatory Commission (Commission).

ACTION: Interim rule and request for comments.

SUMMARY: The Commission amends paragraph (h) of 18 CFR 154.38(h), relating to the recovery of Louisiana First Use Tax by interstate pipelines. Specifically, this rule adds a new clause (9), to establish special refund procedures for flow-through of Louisiana First Use Tax revenues and accrued interest for any interstate pipeline (secondary pipeline) which will receive LFUT funds from another pipeline. Refunds are now required because the Supreme Court, in a judgment issued on June 15, 1981, *Maryland, et al. v. Louisiana*, 49 U.S.L.W. 4709, enjoined the State of Louisiana from further collection of the Louisiana First Use Tax on natural gas and directed Louisiana to refund all revenues collected pursuant to the First Use Tax together with all interest earned on those revenues upon the maturity date of each security in which the revenues and interest have been invested. This rule is consistent with Order No. 10-D recently adopted by the

Commission for so-called "primary pipelines," that is, interstate pipelines which paid the First Use Tax directly to the State of Louisiana and receive LFUT funds directly from Louisiana.

The rule for secondary pipelines is necessary to provide complete and speedy flow-through to jurisdictional pipeline customers of their First Use Tax payments. It requires interstate pipelines which receive LFUT fund refunds from another pipeline to pass through those refunds in lump sum payments, by check, to their jurisdictional customers within certain time periods.

DATES: *Effective date:* The interim rule is to be effective July 22, 1981.

Comments Date: Comments must be filed on or before August 12, 1981, and refer to Docket No. RM81-37. Submit an original and 14 copies.

ADDRESSES: Comments should be mailed to: Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:

Fredrick L. Jaffe, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8150, or

Sherri L. Booye, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-5378.

Before Commissioners: C. M. Butler III, Chairman; Matthew Holden, Jr., and J. David Hughes.

Louisiana First Use Tax: Refund Procedures for Secondary Pipelines, Docket No. RM81-37.

Interim Rule (Issued July 22, 1981)

I. Introduction

By this rule the Federal Energy Regulatory Commission (Commission) amends paragraph (h) of 18 CFR 154.38(h), relating to the recovery of Louisiana First Use Tax by interstate pipelines. Specifically, this rule adds a new clause (9), to establish special refund procedures for flowthrough of Louisiana First Use Tax revenues and accrued interest for any interstate pipeline (secondary pipeline) that will receive LFUT funds from another pipeline.[1] Refunds are now required because the Supreme Court, in a judgment issued on June 15, 1981 *Maryland, et al.* v. *Louisiana*, 49 U.S.L.W. 4709, enjoined the State of Louisiana from further collection of the Louisiana First Use Tax on natural gas and directed Louisiana to refund all revenues collected pursuant to the First Use Tax together with all interest earned on those revenues upon the maturity date of each security in which the revenues and interest have been invested. The first refund was made by Louisiana on July 15, 1981.

This rule is consistent with the rule recently adopted by the Commission [2] for so-called "primary pipelines", that is, interstate pipelines which paid the First Use Tax directly to the State of Louisiana and receive the LFUT funds directly from Louisiana. The rule adopted for the primary pipelines requires these pipelines to make their first refund to the secondary pipelines by August 14, 1981.

The rule for secondary pipelines is necessary to provide complete and speedy flow-through to jurisdictional pipeline customers of their First Use Tax payments. It requires interstate pipelines which receive LFUT fund refunds from another pipeline to pass those refunds in lump sum payments, by check, to their jurisdictional customers within certain time periods.

II. Background

A. *Louisiana First Use Tax.*—The Louisiana First Use Tax was imposed, at a rate of 7 cents per thousand cubic feet ("Mcf"),[3] upon the first "use"[4] of natural gas primarily entering Louisiana from the Outer Continental Shelf.

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[1] Louisiana First Use Tax revenues collected by Louisiana and interest accrued thereon are hereinafter referred to as "LFUT funds."

[2] "Louisiana First Use Tax: Refund Procedures for Primary Pipelines", Docket No. RM78-23, Order No. 10-D, Interim Rule (Issued July 17, 1981). Hereinafter cited as "Primary Pipeline Rule."

B. *Supreme Court Opinion and Judgment.*—On May 26, 1981, the United States Supreme Court issued an opinion in *Maryland* v. *Louisiana* [5] finding the First Use Tax unconstitutional and on June 15, 1981, issued a judgment which enjoined Louisiana from further collection of the Louisiana First Use Tax and directed Louisiana to refund to the pipeline taxpayers, within 30 days of the judgment, all revenues collected pursuant to the First Use Tax, together with all interest earned thereon.[6] At the request of the plaintiff states and the plaintiff-intervenors,[7] the Court further provided that the First Use Tax revenues which have been invested by Louisiana in interest bearing securities are to be refunded by Louisiana as each security matures, to avoid any interest penalty associated with premature termination of these securities. This staggered refund procedure will increase refunds to consumers by at least $17 million.

C. *Commission Action Since the Supreme Court Judgment.*—In response to the Supreme Court's judgment which enjoined Louisiana from any further collection of the First Use Tax, the Commission issued an order on June 29, 1981, to terminate the collection of the First Use Tax by the primary pipelines from their customers.[8] The Commission order directed the twenty pipelines tracking the First Use Tax to cease collection of the tax from their customers, to terminate the tracking of the tax and to file revised tariff rate sheets.

On July 8, 1981, the primary pipelines submitted to the Commission a proposed agreement which establishes the procedures by which Louisiana will refund LFUT funds to the primary pipelines. This agreement provides the method for allocating LFUT funds among the primary pipelines and establishes the dates on which Louisiana will make refunds to the primary pipelines. The total amount that was refunded on July 15, 1981, exceeds $228,500,000 and certificates of deposit in face amounts of $403,325,000 will mature, with interest, between July 20, 1981, and May 14, 1982. The agreement between the primary pipelines and the State of Louisiana provides that funds paid on July 15, 1981, would earn interest to July 14, 1981, and generally that Louisiana will pay the remaining refunds within two business days of the maturity of each remaining certificate of deposit.[9] The settlement agreement was signed by the pipelines on July 10, 1981, and was approved by the Commission on July 13, 1981.[10]

On July 17, 1981, the Commission issued an interim rule for primary pipelines that adopted, with minor substantive changes, the terms of a proposed stipulation tendered to the Commission by several primary pipelines.[11] The rule requires that all LFUT fund refunds made by primary pipelines be flowed through in lump sum payments, by check, to jurisdictional pipeline customers within a specific time period after disbursement of the funds by Louisiana. The rule establishes an allocation methodology that requires pipelines to allocate the refunds based upon the sales volumes of each customer subject to First Use Tax charges. The rule also requires the twenty primary pipelines to report periodically on their compliance with the Commission's regulations.

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[3] 1978 La. Sess. Law Serv. 482 (Act No. 294), La. Rev. Stat. Ann. §§ 47:1301–41:1307 (West 1979 supp.) Hereinafter referred to as "First Use Tax."

[4] The term "use" is defined broadly as "[1] the sale; [2] the transportation in [Louisiana] to the point of delivery at the inlet of any processing plant; [3] the transportation in [Louisiana] of unprocessed natural gas to the point of delivery at the inlet of any measurement or storage facility; [4] transfer of possession or relinquishment of control at a delivery point in [Louisiana]; [5] processing for the extraction of liquefiable component products or waste materials; [6] use in manufacturing; [7] treatment; or [8] other ascertainable action at a point within [Louisiana]." La Rev. Stat. § 47:1302(8).

[5] 49 U.S.L.W. 4502 (1981).

[6] *Maryland v. Louisiana*, 49 U.S.L.W. 4709 (1981).

[7] The United States and the Commission were plaintiff-intervenors.

[8] *Arkansas Louisiana Gas Company, et al.*, Docket Nos. TA81–2–31, et al. (Issued June 29, 1981).

[9] In addition to the July 15, 1981 refund date, Louisiana is required to disburse refunds to the primary pipelines on: July 22, 1981, August 19, 1981, September 16, 1981, October 21, 1981, November 18, 1981, December 16, 1981, March 17, 1982, April 21, 1982, and May 18, 1982.

[10] *Arkansas Louisiana Gas Company, et al.*, Docket Nos. TA81–2–31, *et al.*, "Order Approving Agreement" (Issued July 13, 1981).

D. *Petition for Rulemaking Submitted by the Plaintiff States in Maryland* v. *Louisiana.*—On July 10, 1981, the plaintiff states[12] in *Maryland* v. *Louisiana* filed a petition for rulemaking pursuant to § 1.7(b)[13] requesting that the Commission establish special procedures for disbursement of LFUT fund refunds from the secondary pipelines to their customers.[14] The States argue that any refund procedures should assure that the ultimate consumers of natural gas receive identifiable refunds of LFUT funds at the earliest possible date.

In their petition, the States request that the Commission establish refund procedures for secondary pipelines that parallel the refund procedures for primary pipelines. Specifically, the States request the following:

(1) The first refunds shall be made by check not later than 15 days after the disbursement of the first such refund to them, if possible, with prime rate interest thereafter, and within 30 days in any event;

(2) Subsequent refunds shall be made by check not later than 10 days after the disbursement of subsequent refunds to them, if possible, with prime rate interest thereafter, and within 25 days in any event;

(3) Refunds shall be allocated among customers in proportion to the sales to them during the April 1979 through April 1981 period, based on actual billings for sales if readily available, otherwise based on billing determinants;

(4) The secondary pipelines shall report to the Commission within 15 days of their first refunds and at appropriate dates thereafter, including the total amount of each refund received; the total amounts of each refund flowed through, by customers; the dates of these occurrences; the ratio used to determine the flow through; and whether the ratio was based on actual sales or billing determinants.[15]

III. Policy Considerations

The constitutionality of the First Use Tax was questioned from the date of its enactment and the Commission established uniform special procedures for refund of the tax by the primary pipelines in the event the tax was declared unconstitutional.[16] Since the tax has been declared unconstitutional by the Supreme Court, the Commission adopted a rule which refines the procedures for primary pipelines to conform to the Supreme Court's opinion and judgment.[17] In order to guarantee that LFUT fund refunds will promptly flow beyond the primary pipelines to the ultimate consumer as full and distinctly identifiable refunds, the Commission adopts this interim rule which sets forth the uniform special refund procedures that secondary pipelines must follow in making refunds to their customers.

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[11] The proposed stipulation is summarized in the Primary Pipeline Rule, note 2 *supra* at pp. 6–8. In the interim rule for primary pipelines, the Commission made four minor substantive changes in the proposed stipulation. These changes are set forth in the Primary Pipeline rule at pp. 13–14.

[12] Maryland, Illinois, Indiana, Massachusetts, Michigan, New Jersey, New York, Rhode Island, and Wisconsin. Hereinafter referred to as "the States."

[13] 18 CFR 1.7(b).

[14] "Petition for Issuance, Amendment, Waiver, or Repeal of Rules or Adoption of Declaratory Orders, *State of Maryland, et al.*, Docket No. RM81–37 (filed July 10, 1981) (hereinafter cited as Petition). The States also requested pursuant to 18 CFR 1.7(c) that the Commission adopt such declaratory orders, as may be necessary to flow through LFUT funds from the secondary pipelines to their customers.

[15] Petition, *supra* at 6–7.

[16] Order Nos. 10, 10–A and 10–C. 43 FR 45553 (October 3, 1978), 43 FR 60438 (December 28, 1978), 44 FR 13460 (March 12, 1979), 45 FR 29011 (May 1, 1980), petitions for review pending, *Tennessee Gas Pipeline Co., et al.* v. *FERC*, 5th Cir., Nos. 78–3816, *et al.*, and *Florida Gas Transmission Co.* v. *FERC*, 5th Cir., No. 79–1865.

[17] Primary Pipeline Rule, note 2 *supra*.

A. *Need for a Special Uniform Refund Procedure.*—If the Commission did not adopt a uniform refund rule, secondary pipelines would refund the LFUT funds in accordance with their existing tariff provisions. Generally, the tariff refund provisions provide that refunds should be made either through a credit to Account 191 or through a lump sum refund procedure for refund periods prior to January 1, 1980.[18] The Commission believes that the use of these tariff refund provisions for making LFUT fund refunds may not be adequate to assure that the refunds promptly flow back to those customers that have incurred the cost of the First Use Tax. The tariff provisions for refunds were established for individual pipelines based on their particular gas supply situation and were not designed for large special refunds like the LFUT fund refunds at issue in this rulemaking.

(1) *Allocation of LFUT Fund Refunds.*—Tariffs which require lump sum refunds adopt various methods for allocating the refunds among customers. These tariffs, which are often the result of settlement agreements, may allocate refunds among customers differently than the way funds were collected when the First Use Tax was in effect. Tariff provisions which require refunds to be credited to Account 191 will likely allocate the refunds among customers in a manner different than they were collected simply because of changes in sales patterns over time. The interim rule adopts a uniform allocation methodology which more accurately reflects First Use Tax charges incurred by each customer than the tariff provisions presently in effect.

(2) *Prompt Refunds.*—Tariff refund provisions may not allow for prompt refunds.[19] Refund provisions which require crediting of the refund to Account 191 may take as long as six to eight months (although earning interest in accordance with 18 C.F.R. 154.67(d)) before the refund actually appears as a reduction to a pipeline customers' rates.

The tariff provisions which require lump sum refund procedures may also delay flow through of LFUT funds to the ultimate consumer. Under most lump sum refund procedures, pipelines have a minimum of at least 30 days from the date of receipt or until some refund threshold level is reached to make refunds. The delay could be significant if, for example, the LFUT funds have to pass through 3 or 4 interstate pipelines with lump sum tariff provisions before reaching the ultimate consumer. The ultimate consumer may have to wait at least three or four months before receiving any refunds and as explained below, earn no interest during this delay. Since both existing tariff refund provisions—crediting of Account 191 and lump sum—would not expeditiously flow back the LFUT fund refunds to consumers in a uniform manner, a special refund procedure is warranted.

(3) *Variation in Interest Requirements.* Finally, the significant variations in the interest requirements of the tariff refund provisions warrant adoption of a uniform interest requirement.[20] Some tariff refund provisions require that interest accrue from date of receipt;[21] others provide that no interest accrues until forty-five days after receipt.[22] On refunds credited to Account 191, the tariff provisions often require, in accordance with the

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[18] As a result of the Commission's incremental pricing regulations implementing Title II of the Natural Gas Policy Act of 1978, 15 U.S.C. 3341–3348, lump sum refund procedures have been established in many pipeline tariffs to provide special lump sum refunds to non-exempt customers subject to the program.

[19] The tariff provisions are appropriate when a single supplier refund is involved for a particular pipeline. However, the LFUT refunds will be made on ten different dates over the next year by many interstate pipelines.

[20] The tariff provisions vary because they incorporate provisions of older settlement agreements.

[21] *See e.g.* National Fuel Gas Supply Corporation, First Revised Sheet No. 30C to FERC Gas Tariff Original Volume No. 1:

[22] *See e.g.* Cities Service Gas Company Second Substitute First Revised Sheet No. 64 to FERC Gas Tariff Original Volume No. 1: Paragraph 21.41 "*Gas Supplies Refunds Subject to Flow Through.*"

Commission's regulations,[23] that interest be computed on the month-ending balance in Account 191. This means that the interest earnings will vary from one refund to the next depending on what day the refund is received by the pipeline. A uniform refund procedure would require the same obligations for all pipelines and give the same protections to all customers, eliminating the inequity that a tariff approach would create.

For these reasons, the Commission does not believe it would be in the public interest to flow through LFUT fund refunds in accordance with each pipeline's tariff refund provision. The interim rule will serve to allocate more accurately the LFUT funds among customers who paid it, minimize the time period over which the refund must be made, and standardize the interest obligations of all pipelines. To the extent existing pipeline tariff refund provisions are inconsistent with this rule, the provisions of this interim rule shall apply.

B. *The Interim Rule For Secondary Pipelines.*—The provisions established in this rule for the secondary pipelines reflect most of the provisions adopted with respect to refunds by the primary pipelines in Order No. 10-D. Similar provisions are being adopted for the primary and the secondary pipelines, in part, so that all pipelines required to make LFUT fund refunds will be treated consistently. The Primarly Pipeline Rule established a workable refund methodology that is easily adaptable to the secondary pipelines. By adopting a rule for secondary pipelines that basically tracks the rule for primary pipelines, the Commission is establishing expeditious and uniform procedures for refunding LFUT funds. Such procedures guarantee that all customers will receive refunds in a like manner regardless of which type of pipeline—primary or secondary—supplies their natural gas. However, to take into consideration the different circumstances affecting the secondary pipelines, the length of time required for making refunds and the date interest begins to accrue on these LFUT funds have been lengthened for secondary pipelines.

This rule requires secondary pipelines to make refunds within 30 days of receipt with no interest accruing until the 15th day after receipt. The rule for primaries requires refunds within 25 days of receipt with no interest accruing until the 10th day after receipt. The Commission believes it is necessary and reasonable to allow the secondary pipelines an extra 5 days to make refunds without incurring interest liabilities because the administrative difficulties that will be experienced by secondary pipelines in making refunds are much greater than the administrative tasks facing Louisiana and the primary pipelines.

The administrative tasks performed by Louisiana in making LFUT fund refunds are relatively simple. Louisiana knows the exact amount of money it will be refunding, and the dates it is required to disburse the LFUT funds. In addition, Louisiana must only write a total of twenty seven checks.[24] Given these administrative tasks, Louisiana has two business days to make each refund payout.[25]

The Primary Pipeline Rule allows the primary pipelines 10 days to make interest free refunds. The primary pipelines' administrative tasks are more difficult than Louisiana's because they must make a larger number of refunds than Louisiana. However, the primary pipelines' task is not as complex as that of the secondary pipelines.

The secondary pipelines will not know exactly when they will be receiving their refunds from another pipeline nor will they know the amounts they will receive. In addition, they may have to write substantially more checks. Columbia Gas Transmission

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[23] 18 C.F.R. § 154.38(d)(4)(iv)(c).

[24] In addition to the twenty jurisdictional primary pipelines, there are seven non-jurisdictional pipelines who will also be receiving refunds from Louisiana.

[25] See note 10, *supra*.

Corporation (Columbia), for example, is both a primary and a secondary pipeline for purposes of the LFUT fund refunds. It receives natural gas supplies from several different pipelines. Columbia could receive LFUT fund refunds from each of its pipeline suppliers on a different day. As a result, Columbia's staff could be constantly processing these incoming LFUT fund refund checks, calculating allocations of the money, and writing, processing and mailing checks to their approximately 80 jurisdictional customers. This administrative work is time consuming. The Commission therefore finds that an interest free period of 15 days after receipt of each LFUT fund refund is not unreasonably long.

At the same time, the Commission finds that an interest free period of longer than 15 days is not warranted, because the administrative tasks, while time consuming, are purely mechanical. The most time consuming procedure for the secondary pipelines is the calculation of billing determinants (needed to allocate the LFUT fund refunds). The secondary pipelines will only have to calculate the LFUT fund refund billing determinants once, prior to receipt of their first LFUT fund refund, since the same billing determinants will also be used for all subsequent refunds. They will have the period from the effective date of this rule until they receive their first LFUT fund refund to make these billing determinant calculations.

IV. *Summary of the Rule*

(1) *Method of Allocation.* The interim rule requires that jurisdictional LFUT fund refunds made by secondary pipelines be flowed through in lump sum payments by check to jurisdictional customers. The interim rule establishes an allocation methodology for LFUT fund refunds which reflects the First Use Tax charges incurred by each pipeline customer. Basically it requires the pipelines to allocate the refunds based upon the sales volumes of each customer subject to First Use Tax charges.

(2) *Time Period for Making Refunds and Interest Provisions.* In the interim rule, the Commission requires the secondary pipelines which receive LFUT funds from another pipeline to make lump sum refunds within a specified time period after receipt of the funds from such other pipeline. The rule requires these pipelines to make refunds within 30 days of receipt. If refunds are not made within 15 days of receipt, the pipelines are required to pay interest in accordance with § 154.67(d) on these refunds from the 15th day after the date of receipt to the date the refund is disbursed to the pipelines' customers.

Finally, the refund requirements for secondary pipelines are subject to certain threshold triggers, with interest accruing after the initial 15 day period.

(3) *Refund Reports—Pipeline Compliance With Commission's Regulations.* In implementing the LFUT refund procedures, the Commission finds that there must be some mechanism by which it can assure that First Use Tax refunds are being made in compliance with its procedures. The interim rule requires them to make periodic reports to the Commission which show the following:

(1) the date of refund;

(2) the total amount of the refund received by the pipeline;

(3) the amount flowed through to each of its jurisdictional customers, by customer;

(4) the date of each such flow through; and

(5) the ratio used to determine the flow through for each of its jurisdictional customers and the basis on which that ratio was determined.

IV. *Effective Date and Comment Procedure*

The interim regulations established by this rule are effective immediately.

Publication of a proposed rulemaking for notice and public comment thereon, and publication 30 days prior to the effective date of the rule have been omitted for good cause in accordance with section 553 of the Administrative Procedure Act (5 U.S.C. 553) because delay in implementing the rule would be contrary to the public interest. The Supreme Court's judgment in *Maryland* v. *Louisiana, supra*, required the State of Louisiana to refund a large portion of the LFUT funds by July 15, 1981. Unless the rule is effective immediately upon issuance, secondary pipelines will be subject to their tariff refund provisions which would not allow for prompt, full refunds. These special refund procedures must be immediately put into place so that interstate pipelines, distributors and state commissions can effectively flow through the refunds to the ultimate consumers.

Comments will be accepted on the interim rule and amendments to the rule will be considered with particular emphasis on any prospective refunds. Unless comments present compelling reasons to change provisions as to refunds made prior to issuance of the final rule, the Commission will not be inclined to impose any amendments retroactively.

Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. Each person submitting a comment should include his name and address and identify Docket No. RM81-37, and give reasons for any recommendations. An original and 14 copies should be filed with the Secretary of the Commission. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street NE., Washington, D.C. 20426, during regular business hours. All comments should be received by the Commission by August 12, 1981.

Upon review of the comments, the Commission will consider whether public hearings are warranted.

(Natural Gas Act, 15 U.S.C. 717-717w; Department of Energy Organization Act, 42 U.S.C. 1701-7352; Administrative Procedure Act, 5 U.S.C. 553)

In consideration of the foregoing § 154.38(h), Part 154 of Title 18, Code of Federal Regulations, is amended as set forth below, effective July 22, 1981.

By the Commission. Commissioner Hughes dissents for the reasons set forth in his dissent to the Interim Rule issued July 17, 1981 in Docket No. RM78-23.

Kenneth F. Plumb,
Secretary.

[¶ 30,281]

46 F. R. 38910 (July 30, 1981)

18 CFR Part 271

[Docket No. RM80-53]

Maximum Lawful Prices Under the Natural Gas Policy Act for August, September, and October, 1981

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: Pursuant to the authority delegated by 18 CFR 357.307(l), the Director of the Office of Pipeline and Producer Regulation revises and publishes the maximum lawful prices prescribed under Title I of the Natural Gas Policy Act (NGPA) for the months of August, September and October, 1981. Section 101(b)(6) of the NGPA required that the Commission compute and publish the maximum lawful prices before the beginning of each month for which the figures apply.

EFFECTIVE DATE: July 23, 1981.

FOR FURTHER INFORMATION CONTACT: Kenneth A. Williams, Director, OPPR (202) 357-8500.

SUPPLEMENTARY INFORMATION: July 23, 1981.

Section 101(b)(6) of the Natural Gas Policy Act of 1978 (NGPA) requires that the Commission compute and make available maximum lawful prices and inflation adjustments prescribed in Title I of the NGPA before the beginning of any month for which such figures apply.

Pursuant to this requirement and § 375.307(l) of the Commission's regulations, which delegates the publication of such prices and inflation adjustments to the Director of the Office of Pipeline and Producer Regulation, the maximum lawful prices for the months of August, September and October, 1981, are issued by the publication of the price tables for the applicable quarter. Pricing tables are found in § 271.101(a) of the Commission's regulations. Table I of § 271.101(a) specifies the maximum lawful prices for gas subject to sections 102, 103, 106(b)(1)(B), 107(c)(5), 108, and 109 of the NGPA. Table II of § 271.101(a) specifies the maximum lawful prices for sections 104 and 106(a) of the NGPA. Table III of § 271.102(c) contains the inflation adjustment factors.

Kenneth A. Williams,

Director, Office of Pipeline and Producer Regulation.

[¶ 30,282]

46 F. R. 38912 (July 30, 1981)

18 CFR Part 282

[Docket No. RM81-27; Order No. 167]

Incremental Pricing: Adoption of Single-Tier Alternative Fuel Pricing Ceiling

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule, subject to congressional review.

SUMMARY: The Federal Energy Regulatory Commission is amending Part 282 of its regulations regarding incremental pricing under Title II of the Natural Gas Policy Act of 1978 (NGPA). The rule is subject to Congressional review and will not become effective if disapproved by either House of Congress. If not disapproved, the rule will amend §§ 282.204(e)(2)(iii), 282.402, and 282.403 to permanently exempt all facilities subject to incremental pricing from the No. 2 fuel oil ceilings, and in so doing, establish a single-tier high-sulfur No. 6 alternative fuel price ceiling. The rule is issued pursuant to section 206(d) of the NGPA.

DATES: Effective the day following the expiration of 30-day Congressional review period if not disapproved by either House of Congress.

FOR FURTHER INFORMATION CONTACT:

Thomas P. Gross, Federal Energy Regulatory Commission, 825 North Capitol Street, NE, Washington, D.C. 20426, (202) 357-8171

James Liles, Federal Energy Regulatory Commission, 825 North Capitol Street, NE, Washington, D.C. 20426, (202) 357-8158

Issued: July 24, 1981.

The Federal Energy Regulatory Commission (Commission) is amending its regulations on incremental pricing (18 CFR Part 282) under Title II of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3301-3432). Specifically, §§ 282.204(e)(2)(iii), 282.402 and 282.403 are amended to permanently exempt all facilities subject to incremental pricing from the No. 2 fuel oil ceilings and in so doing establish a single-tier, high-sulfur No. 6, alternative fuel price ceiling.

I. Background

Title II of the NGPA requires the Commission, within certain guidelines, to institute and administer an incremental pricing program. The program is designed to pass through, by surcharge, a portion of the increases in the wellhead prices of natural gas allowed under Title I of the NGPA to certain industrial facilities that use natural gas as boiler fuel. The purpose of the program is to shield high-priority customers from the natural gas price increases permitted under Title I and to prepare the market for deregulation of natural gas pricing in 1985.

Generally under Title II of the NGPA the incremental pricing surcharge applicable to a particular facility is the difference between the price that otherwise would have been paid for

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natural gas by that facility and the price at which the facility can purchase alternative fuel. The price of the alternative fuel (the alternative fuel price ceiling) is determined in accordance with section 204(e) of the NGPA. Section 204(e)(1) provides that the alternative fuel price ceiling for an incremental pricing region is the price of No. 2 fuel oil that is determined by the Commission to be paid by industrial users in that region. Section 204(e)(2) provides that the Commission may reduce the alternative fuel price ceiling to an amount not lower than the price for No. 6 fuel oil, if it determines that the reduction is necessary to prevent an increase in rates and charges to residential, small commercial, and other high priority customers.

On September 28, 1979, the Commission issued a rule in Docket No. RM79-21, (Order No. 50) implementing section 204(e) by establishing a three-tier system for alternative fuel price ceilings.[1] Under this system, three alternative fuel price ceilings are to be published for each incremental pricing region. The three price ceilings are calculated on the basis of sales in the region of No. 2 fuel oil, low-sulfur No. 6 fuel oil, and high-sulfur No. 6 fuel oil.[2] The price ceiling applicable to any industrial boiler fuel facility is the price of No. 2 fuel oil in the region in which the facility is located, unless the facility can demonstrate that it has the installed capability and legal authority to burn a lower priced fuel oil. If so, the ceiling which corresponds to the lowest priced fuel oil that the facility has the installed capability and legal authority to burn becomes the facility's price ceiling.

The Commission determined that immediate implementation of the three-tier system was inappropriate (for reasons discussed below) and, accordingly, issued a second rule in Docket No. RM79-21 (Order No. 51),[3] postponing the application of the three-tier, alternative fuel price ceilings. Order No. 51 provided that from January 1, 1980 until November 1, 1980, the alternative fuel price ceiling for each region would be established by the price of high-sulfur No. 6 alternative fuel oil. This "single-tier" system was issued under the authority of section 206(d) of the NGPA,[4] and essentially, temporarily exempted industrial facilities from incremental pricing surcharges which would otherwise result from application of an alternative fuel price ceiling above the price of high-sulfur No. 6 fuel oil.

Because the Commission subsequently foresaw that its concern regarding the three-tier system would not be resolved by November 1, 1980, it issued another rule in Docket No. RM79-21 (Order No. 81),[5] which extended the application of a single-tier, high-sulfur No. 6 fuel oil, ceiling until October 31, 1981. Presently, the three-tier system is scheduled to take effect on November 1, 1981.

On April 22, 1981, the Commission issued a Notice of Proposed Rulemaking,[6] proposing to amend its incremental pricing regulations at §§ 282.402 and 282.403 to permanently exempt all facilities subject to the program from the No. 2 fuel oil ceiling, and in so doing, to establish a single-tier, high-sulfur No. 6 alternative fuel price ceiling. Interested persons were afforded the opportunity to present data, views and comments at a public hearing held May 28, 1981 and to file written comments by May 29, 1981.[7]

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[1] "Regulations Implementing Alternative Fuel Cost Ceilings on Incremental Pricing under the Natural Gas Policy Act of 1978," Docket No. RM79-21, Order No. 50, issued September 28, 1979, 44 FR 57754 (October 5, 1979).

[2] No. 2 fuel oil (also known as distillate fuel oil) is the highest priced of the three tiers. High-sulfur No. 6 fuel oil (also known as residual fuel oil) is the lowest priced of the three tiers.

[3] "Rule Exempting Industrial Boiler Fuel Facilities from Incremental Pricing Above the Price of No. 6 Fuel Oil," Docket No. RM79-21, Order No. 51, issued September 28, 1979, 44 FR 57778 (October 5, 1979).

[4] Section 206(d) of the NGPA permits the Commission, by rule or by order, to provide for the exemption, in whole or in part, of any other incrementally priced facility or category from the incremental pricing program, subject to Congressional review.

[5] "Rule Further Exempting Industrial Boiler Fuel Facilities from Incremental Pricing Above the Price of No. 6 Fuel Oil and Applying Ceiling Prices to Forty-Eight Incremental Pricing Regions," Docket No. RM79-21, Order No. 81, issued May 7, 1980, 45 FR 31300 (May 13, 1980).

[6] "Incremental Pricing: Adoption of Single-Tier Alternative Fuel Price Ceiling", Docket No. RM81-27, issued April 27, 1981, 46 FR 23947 (April 29, 1981).

A number of written and oral comments were received in response to the Commission's Notice of Proposed Rulemaking in this docket, with most of the comments supporting the proposed rule. The Commission has carefully considered these comments as well as the effect that a three-tier system would have in furthering the goals of incremental pricing and the impact it would have on certain industrial facilities and on the economy. In view of these considerations, the Commission has decided to exempt all facilities subject to the program from the No. 2 fuel oil ceiling, and in so doing, establish on a permanent basis, a single-tier alternative fuel price ceiling at the level of high-sulfur No. 6 fuel oil. The Commission's authority to establish this price ceiling is based on section 206(d) of the NGPA.

II. Discussion

Price Shielding. As previously discussed, the incremental pricing program was designed to pass through, by surcharge, a portion of the increases in the wellhead prices of natural gas allowed under Title I of the NGPA to certain industrial facilities that use natural gas as boiler fuel. One purpose of the program is price shielding, *i.e.* the shielding of high-priority customers from the natural gas price increases permitted under Title I.

One factor the Commission must consider in implementing the incremental pricing program is that the potential impact of the program has been minimized by the relatively small number of facilities subject to incremental pricing. The number of participants in the program is limited for several reasons.

First, under the statutory scheme of Title II, facilities served by intrastate pipelines are generally not subject to incremental pricing. This factor keeps a large segment of the industrial gas market, particularly the market in the gas producing states traditionally served by intrastate pipelines, out of the program.

Second, the scope of incremental pricing has been significantly reduced. At the time of enactment of the NGPA the incremental pricing program was envisioned as eventually being imposed on a wide variety, and large number, of industrial users. As required by section 202 of the NGPA, the Commission issued a rule[8] that would have expanded the incremental pricing program to cover industrial facilities not originally included in the program.[9] That rule was subject to Congressional review and was vetoed. As a result, the scope of the incremental pricing program has been significantly curtailed.

Finally, Congress has established a number of statutory exemptions including small users[10], schools, hospitals, electric generation by utilities, qualifying electric cogeneration facilities, and agricultural facilities.[11] Similarly, the Commission has promulgated rules exempting new small users [12] and mechanical cogeneration facilities.[13]

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[7] The deadline to submit written comments was extended from May 22, 1981 to May 29, 1981 by notice issued May 21, 1981, 46 FR 28672 (May 28, 1981).

[8] "Rule Required under Section 202 of the Natural Gas Policy Act: Incremental Pricing", Docket No. RM80-10, issued May 6, 1980, 45 FR 31622 (May 13, 1980.)

[9] "Regulations Implementing the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978", Docket No. RM79-14 Order No. 49, issued September 28, 1979, 44 FR 57726 (October 5, 1979).

[10] A small user is one whose average daily use of natural gas was 300 Mcf or less during a statutorily-established historical period. *See* 18 CFR 282.203(a)(1).

These exemptions leave only approximately 1500 facilities [14] in the incremental pricing program to bear the impact of the surcharges and to shoulder the burden of meeting the goals of incremental pricing. In most cases, this burden amounts to surcharges in the thousands or hundreds of thousands of dollars per year.[15] However, although these surcharges may be substantial there is very little benefit to consumers by way of price shielding because there are so few incrementally priced users and so many high-priority consumers to share the benefits.

The Commission promulgated the three-tier system to maximize the surcharge absorbed by industrial facilities, and at the same time prevent the loss of consumers who have the option of switching to alternative fuels less expensive than No. 2 fuel oil. However, the Commission now believes that imposition of the three-tier rather than the single-tier program will not significantly increase the price shielding impact of incremental pricing. The Commission believes that the large increases in price ceilings which would result from implementation of the three-tier system would cause facilities that do not now possess the capability for using No. 6 fuel oil as an alternative fuel to make substantial investments to acquire that capability, primarily for the purpose of qualifying for a lower incremental pricing surcharge.

Many of the comments provided information which supports the view that the additional surcharges incrementally priced facilities would have to pay under a three-tier system would economically justify investment by such facilities in high-sulfur No. 6 fuel oil capability.[16] Many of these facilities have not previously made this investment because it was not to their economic advantage given the limited need for an alternative fuel. Several areas of the country have historically experienced little or no curtailment. Facilities located in such areas either have no alternative fuel capability or possess No. 2 fuel oil capability that is used solely as a back-up. The higher priced No. 2 fuel oil has never been an economic alternative fuel for these facilities over the long run. The record shows that imposing a No. 2 fuel oil price on a permanent basis would provide sufficient incentive for many of these facilities to install No. 6 capability.

Testimony and data submitted by the commentors indicate that investments in the purchase and installation of equipment to burn high-sulfur No. 6 fuel oil can usually be recovered by means of reduced incremental pricing surcharges in less than a year, and in some cases, substantially shorter periods of time.[17] For example, comments submitted by Armour and Co. at the public hearing [18] demonstrate that if a three-tier system were implemented, the increased cost to the Armour-Dial Soap manufacturing plant in Aurora, Illinois would be approximately $4,750,000 per year. By contrast, the cost of installing No. 6 capability would be

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[11] Agricultural facilities were originally exempt pursuant to section 206(b)(1) of the statute and are currently exempt pursuant to a rule adopted by the Commission and approved by the Congress pursuant to section 206(d). *See* 18 CFR 282.23(a)(2).

[12] 18 CFR 282.203(b).

[13] 18 CFR 282.209.

[14] This figure includes facilities in states that have a state-wide plan, i.e., in states that have raised the retail rate of natural gas to non-exempt industrial facilities to the level of the alternative fuel price ceiling established by the federal plan.

[15] *See* interstate pipeline data submitted pursuant to 18 CFR 282.603.

[16] *See, e.g.*, written comments of: United Distribution Companies (and supporting affidavits), Southern California Gas Company, Northern Illinois Gas Company, Wisconsin Gas Company, Indiana Gas Company; and oral comments of Armour and Co. at the May 29, 1981 public hearing, transcript at pp. 35–45.

[17] The recovery time is further shortened by investment tax credits and other tax incentives for capital investments, thereby enhancing the economic incentive to invest in high-sulfur No. 6 fuel oil capability.

[18] See transcript of the May 29, 1981 meeting, pp. 36–38.

$228,000. Armour states that it would immediately install this capacity for the sole purpose of avoiding the higher surcharges.[19] For all practical purposes, such expenditures would result in the three-tier system evolving into a single-tier system using the price of No. 6 fuel oil. Any benefits derived from a three-tier system would be short-lived as it evolved into a single-tier system.

The Commission believes that the three-tier system would not only evolve into a single-tier system but that it would do so at great expense to incrementally priced users of natural gas. As illustrated by the above example, incrementally priced users would be encouraged to make wasteful capital investments in alternative fuel facilities for the primary purpose of avoiding the additional surcharges arising from a three-tier system. Such expenditures would divert funds from more useful capital investments.

The Commission also shares the concerns raised by several commentors about the economic consequences that implementation of the three-tier system would have on those remaining facilities that do not possess sufficient capital to install residual oil capability or whose gas consumption is too small to economically justify installation of residual oil capability. As United Distribution Companies, Process Gas Consumers Group and others commented, an additional surcharge in the range of two or three dollars per Mcf would likely force some facilities to shut-down or sharply curtail their production. United Gas Pipeline Company stated that in some cases these plants are the primary source of income for the community in which they are located and their closure would have a severe economic impact on the community. The New York Public Service Commission expressed similar concerns, noting that older facilities in the state might be closed, and jobs and related taxes transferred to other regions of the country where energy costs are not as high. High priority gas customers may also experience greater costs due to the load loss on the distributor's system.

The Commission expects that those facilities which remain in business but are unable to install alternative fuel capability will encounter severe financial problems. The financial problems encountered by facilities under the single-tier program have been demonstrated by the Commission's experience with adjustment requests filed pursuant to section 502(c) of the NGPA. The number of adjustment requests filed with the Commission seeking relief due to financial hardship from incremental surcharges has increased markedly during this past winter heating season as the incremental price ceilings have increased. Many of these facilities have paid surcharges of $1 per Mcf or more in the past few months. The Commission is concerned that the number of facilities encountering financial hardships could dramatically increase if facilities were paying additional surcharges in excess of $2 per MMBtu as determined under a three-tier system.

One comment urging adoption of a three-tier system suggested that capital investment in No. 6 fuel oil burning equipment could be discouraged by providing that facilities may not qualify for the lowest-tier price unless they used high-sulfur No. 6 fuel oil on the date on which they last used a petroleum-based fuel or on a date specified by the Commission.

For the following reasons, the Commission does not accept this suggestion. Adopting a rule tying the ceiling to the alternative fuel last used would simply encourage industrial users to invest in and use alternative fuel capability for the purpose of avoiding the incremental pricing surcharge. Moreover, as to incrementally-priced users, it would discourage the use of any fuel oil other than high-sulfur No. 6.

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[19] Comments submitted by Southern California Gas Company (SoCal) confirm the economics of such investment in California. SoCal states that the California Public Utilities Commission implemented two-tier rates for low priority users. As of April 20, 1981, SoCal received affidavits from 47 customers indicating they have installed the necessary facilities to burn No. 6 fuel oil to take advantage of a 30 cents per MMBtu price differential. By comparison the price difference between No. 2 fuel oil and high-sulfur No. 6 fuel oil is generally in excess of $2 per MMBtu.

The second alternative, fixing a date after which installation of No. 6 fuel oil capability would not qualify the facility for the No. 6 fuel oil ceiling, would simply be unfair. Such a rule would not respond to legitimate changed circumstances. The Commission believes that the price ceiling applicable to an industrial boiler fuel user should change as his fuel use capability changes.

In summary, the Commission believes that the adverse economic consequences of implementing a three-tier approach overshadow the possible benefits of any short-term price shielding. If a large number of facilities were to install No. 6 capability, as the record indicates, and if marginal firms were forced to shut down because of the increased cost of their fuel, the additional surcharges collected under the three-tier approach would be minimal. At the same time, it is likely that implementation of the program would, in many cases, promote extensive wasteful capital expenditure, and, in some cases, failure of marginal firms. The Commission therefore does not believe implementation of the three-tier approach would provide an overall benefit to high priority users.

Market Ordering. Another purpose of incremental pricing is to prepare the market for deregulation in 1985. Congress recognized that under the NGPA pricing scheme interstate pipelines would be in a position to outbid intrastate pipelines in acquiring new gas supplies after deregulation. The potential of interstate pipelines to pay more for new supplies results from the fact that only a portion of all interstate gas will be deregulated in 1985 under Title I of the NGPA.[30] Because much of the "old" interstate gas will remain under price regulation after 1985 the interstate pipelines will be able to "role in" high-priced, new gas with the lower-priced, regulated gas so that the average price will remain competitive with alternate fuels.

Incremental pricing is designed to minimize this effect by allocating a portion of the price increases resulting from deregulation to the interstate end-users who ideally are the most responsive to price changes (*i.e.*, the low-priority users). Since it was expected that these end-users would reduce their gas consumption (through conservation or fuel switching) as their gas costs increase, the interstate pipelines were expected to be faced with decreased demand and a shrinking market, and thereby to be induced to restrain their bidding for high-priced supplies. If the ability of the interstate pipelines to pay extremely high prices for new gas were so limited, the intrastate pipelines could remain in the market for such supplies. Other market-ordering functions would also be served, such as restraining the average price of interstate gas and limiting the windfall profits which producers would obtain from the high prices.

The Louisiana Resources Company (Louisiana Resources), an intrastate pipeline, filed comments expressing its concern that a single-tier system would not adequately serve this "market ordering" function of the incremental pricing program. Louisiana Resources expects that it will be unable to obtain new gas supplies once deregulation occurs. Specifically, it is concerned that the single-tier program will minimize the market ordering impact of the incremental pricing program.

The Commission recognizes that the incremental pricing program was originally designed by Congress to serve a market-ordering as well as a price shielding function.[31] However, a number of factors undermine the program's effectiveness in meeting those goals. As previously discussed in this rule and at greater length in Docket No. RM80-10, only a small fraction of the total interstate market is subject to incremental pricing. The Commission estimates that 900 Bcf is consumed for non-exempt uses, while approximately 14 Tcf is sold in the interstate market. Thus, less than 7% of the market is subject to the program. It appears reasonable to expect that such a very small portion of the market could do little to restrain the wellhead price of natural gas.

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[30] *See* section 121 of the NGPA.

[31] See the discussion in the "Rule Required Under Section 202 of the Natural Gas Policy Act: Incremental Pricing," Docket No. RM80-10 issued May 6, 1980, 45 FR 31622 *et seq.*, (May 13, 1980).

Moreover, the relationship between the wellhead price of gas and the burner tip price paid by non-exempt customers has become quite tenuous. Because there are so few non-exempt users in the incremental pricing program and state regulatory authorities are retaining the benefits of incremental pricing within their own state, non-exempt users generally have been priced at the incremental pricing ceilings. With all non-exempt users already at the ceilings, most price increases for gas in the field flow directly to exempt users. Consequently, the customers who are least able to respond to price increases (*i.e.*, the high-priority customers) bear the effect of wellhead price increases and little bidding restraint results.

Louisiana Resources' comments indicate that they are aware of some of the practical limitations on the efficacy of incremental pricing as a market-ordering mechanism. Nevertheless, Louisiana Resources argues that: (1) a market-ordering mechanism is needed; (2) incremental pricing is the only such mechanism available; and (3) the three-tier system will probably serve to restrain interstate demand more than a single-tier high-sulfur No. 6 oil price ceiling. Louisiana Resources proposes two alternatives to implementing a single-tier system on a permanent basis. First, they propose that the Commission develop a companion rule designed to deal with the market-ordering problem. Consideration of the proposed rule in this docket would be deferred until the companion rule is developed. In the alternative, they propose that the Commission reject the proposed rule and implement the three-tier system on a trial basis. Louisiana Resources further states that the Commission should "at the very least" adopt another temporary one-year exemption to the three-tier pricing scheme.

The Commission does not accept these proposals. The first proposal offers no suggestion as to the type of market-ordering alternative the Commission should consider in a companion rulemaking. The Energy Information Administration (EIA) will require several months to implement the three-tier price ceilings. Because the three-tier ceilings are scheduled to go into effect on November 1 of this year, the EIA must know within a very short period of time whether to begin the difficult and costly implementation process. The soliciting of suggestions and the development of such market ordering alternatives in a companion rulemaking would require more time than is available.

The second proposal, implementation of the three-tier ceilings on a trial basis, is defective for other reasons. The market for gas at the wellhead is presently ordered by the ceiling prices under Title I of the NGPA. The market-ordering function of incremental pricing will not be needed until those ceiling prices are lifted in 1985. A trial period of the three-tier system at the present time, when nearly all gas is subject to price controls (well below the price of competing fuels), would be an empty exercise. It is simply not reasonable to expect that wellhead prices would be reduced below their statutorily-mandated price ceilings by the implementation of a three-tier incremental pricing program. The ability of interstate pipelines to market gas, at least to non-exempt users, may be restrained under the three-tier price ceilings. But demand restraint for its own sake is not in the public interest at this time.

The Commission recognizes the potential seriousness of the market-ordering problem raised by Louisiana Resources. However, the Commission does not believe that imposing a three-tier incremental pricing program in November of 1981 is an appropriate response to the problem. To the extent this issue remains relevant when natural gas is deregulated, individuals may request the Commission to reconsider implementing a more effective market-ordering mechanism at that time.

Other Considerations. The Commission believes that the reasons discussed above provide a sufficient basis for implementing the single-tier alternative fuel price ceiling at the level of high-sulfur No. 6 fuel oil on a permanent basis. However, the Commission is also concerned that expanding the incremental pricing surcharge to a three-tier system would exacerbate the already existing problems associated with the calculation of price ceilings. Under the single-tier program, the Commission has experienced serious difficulties, in view of the present fluctuations in oil prices, in developing a methodology that yields alternative fuel price ceilings which accurately reflect the current price of fuel oil, on a monthly basis, for the individual states. Other problems have involved price disparities among neighboring regions, and the fact that many facilities could buy alternative fuel in neighboring states at a lower price than the price ceiling calculated for their own state. If such facilities purchased lower priced alternative fuels, load loss on the system may result. Thus a higher proportion of fixed system costs will be shifted to high-priority gas customers,[25] thereby defeating one purpose of the incremental pricing program, the partial shielding of high-priority users from high natural gas costs. The Commission believes that such problems will only be exacerbated under a three-tier system.

Finally, in its Notice of Proposed Rulemaking in this docket, the Commission stated that the permanent single-tier alternative fuel price ceiling proposed in that Notice and established by this Final Rule would be issued pursuant to section 206(d) of the NGPA as were Order Nos. 51 and 81. However, interested persons were invited to submit comments and data relating to the required findings under section 204(e)(2) of the NGPA.

Many commentors expressed views on the Commission's authority to establish a single-tier alternative fuel price under section 204(e) or section 206(d) of the NGPA. In particular, comments submitted by the National Consumer Law Center and the Midwest Fuel Oil Council questioned the Commission's authority to establish a single-tier system under section 206(d) of the NGPA.

It is the Commission's view that section 206(d) of the NGPA provides the authority to exempt all boiler fuel facilities subject to the program from section 204(e) of the NGPA insofar as that section requires surcharges above the price of high-sulfur No. 6 fuel oil. This view is supported by the statutory language of section 206(d), the legislative history and Congressional intent behind section 206(d), and the recent decision in *Ohio Association of Community Action Agencies et al.* v. *Federal Energy Regulatory Commission, et al.*, No. 81-1208 (D.C. Cir. June 15, 1981) affirming the Commission's use of section 206(d) authority in promulgating Order No. 51.

III. Summary of the Rule

This rule amends §§ 282.204(e)(2)(iii), 282.402, and 282.403 of the Commission's current regulations. Current § 282.402(a), which states that a facility's alternative fuel capability is to be determined in accordance with § 282.403, is deleted. Current § 282.402(b)(1), which provides for the determination and publication of alternative fuel price ceilings based on sales of No. 2 fuel oil, low-sulfur No. 6

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[25] Peoples Gas Light and Coke Company submitted an affidavit stating that the potential price increase to residential customers from large volume load loss is almost $75 per year.

fuel oil and high-sulfur No. 6 fuel oil, is also deleted.

Current § 282.402(b)(2), with three changes, now becomes the general exemptive rule in revised § 282.402. The changes are: (1) all industrial boiler fuel facilities subject to incremental pricing are exempt from section 204(e) of the NGPA insofar as it requires surcharges above the price of high-sulfur No. 6 fuel oil; (2) the published price ceiling is the price ceiling for high-sulfur No. 6 fuel oil; and (3) the clause relating to the alternative fuel capability of the facility is deleted. Thus, revised § 282.402 exempts all industrial boiler fuel facilities subject to the program from any surcharge in excess of the price of high-sulfur No. 6 fuel oil, and provides that the alternative fuel price ceiling applied to a non-exempt industrial boiler fuel facility for any month is the ceiling which is published for high-sulfur No. 6 fuel oil for that month for the incremental pricing region in which the facility is located.

Current § 282.402(c), which provides the temporary imposition of a single-tier system, is deleted.

Current § 282.403(a) provides that an incrementally-priced facility is deemed to have the capability of using No. 2 fuel oil as an alternative to natural gas, unless the facility is certified to have the capability to burn other specified fuel oils. Paragraphs (b) through (l) of current § 282.403 establish the requirements for obtaining certification. Since under the proposed rule, the alternative fuel price ceiling applicable to all facilities would be high-sulfur No. 6 fuel oil, current § 282.403 is deleted in its entirety. Section 282.204(e)(2)(iii), which requires non-exempt industrial boiler fuel facilities to indicate the alternative fuel capability of each facility, is deleted because section 282.403 is deleted.

IV. Certification of No Significant Economic Impact

The Regulatory Flexibility Act (RFA) [23] requires certain statements, descriptions and analyses of proposed rules that will have "a significant economic impact on a substantial number of small entities."

Pursuant to section 605(b) of the RFA, the Commission finds that the provisions of that Act do not apply to this rulemaking. This rulemaking permanently establishes the program already in effect for alternative fuel price ceilings. The program continues to use the single-tier price ceiling (at the level of high-sulfur No. 6 fuel oil) and does not impose any additional requirements. Those who are required to comply with the EIA data filing requirements of this program are generally large oil dealers whose individual sales of high-sulfur No. 6 fuel oil are in excess of 4000 gallons.

Therefore, this rulemaking does not impose any regulatory or administrative burden upon small entities, nor does it require an expense of resources by such entities. For these reasons, the Commission hereby certifies that this rulemaking does not have a significant impact on a substantial number of small entities.

V. Congressional Review and Effective Date

Rules issued pursuant to section 206(d) of the NGPA are required to be submitted to Congress prior to becoming effective. After submission to each House of Congress the rule will take effect following 30 days of continuous session of Congress (as set forth in section 507(b) of the NGPA), unless either House of Congress adopts a resolution of disapproval within the 30-day period. Accordingly, this rule will be effective on the day following expiration of the 30-day period for Congressional review.

Congress will therefore have the opportunity to review the considerations inherent in the choice between a single-tier or three-tier system. If Congress disapproves this exemption, the three-tier system will go into effect.

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[23] 5 U.S.C. 601-612 (Pub. L. 96-354, September 19, 1980).

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301 *et seq.* Department of Energy Organization Act, 42 U.S.C. 7701 *et seq.* E.O. 12009, 42 CFR 46267 (1978))

In consideration of the foregoing, the Commission is amending Part 282, Subchapter I of Chapter I, Title 18 of the *Code of Federal Regulations,* as provided below.

By the Commission. Chairman Butler concurred with a separate statement attached. Commissioner Holden concurred, separate statement will follow later.

Kenneth F. Plumb,
Secretary.

Butler, Chairman, Separately

Issued July 24, 1981.

The primary purpose of these separate concurring views is to consider specifically the comments of one respondent who raises, in my opinion, the most critical issues of this rulemaking. Indeed, the questions raised have implications that range well beyond the direct subject of the rulemaking, as will be pointed out.

Louisiana Resources Company (Louisiana Resources) does not describe itself in detail in its comments. However, the company is an intrastate pipeline serving Louisiana consumers, and apparently is affiliated with The Williams Companies. Louisiana Resources' interest in this proceeding is described by it as follows:

> Louisiana Resources has an interest in this rulemaking because of the proposed rule's effect on the balance between the interstate and intrastate natural gas industries. Briefly put, Louisiana Resources suggests that * * * the rule * * * will * * * significantly alter the balance created by the [Natural Gas Policy Act (NGPA)] between similar classes of customers served by interstate and intrastate pipelines. Louisiana Resources thus argues that the proposed rule, resulting as it does, in light of the NGPA, in the patent discrimination against the intrastate natural gas industry, must not be adopted. Louisiana Resources Comments at 3–4 (footnotes omitted).

Louisiana Resources explains that its problems stem from the manner in which the NGPA altered competitive characteristics of the interstate and intrastate natural gas industries. Prior to the passage of the NGPA, interstate pipelines were permitted to pay only cost-based rates for natural gas, while intrastate pipelines were able to pay higher market prices for gas. Thus, prior to the NGPA, intrastate pipelines had a significant buying advantage relative to interstate pipelines, a fact which Louisiana Resources failed to point out. However, the advantage was not without its adverse consequences because, as a general proposition, the weighted average cost of gas to intrastate pipelines evolved to a higher level than that of the interstate pipelines. Additionally, price redetermination clauses have resulted in substantially increased average gas costs to intrastate pipelines. The differential in average gas costs between interstate and intrastate pipelines combined with the effects of the NGPA has *reversed* the relative buying advantages of the two classes of pipelines. This is the present market-ordering problem.[1]

Under the regime of the NGPA the market-ordering problem develops this way. First, the NGPA provides for only partial decontrol of natural gas. Some gas was deregulated rather quickly. More will be deregulated by 1985. And the remainder, the so-called old gas, will remain under price controls until it is exhausted. Much of this relatively low-cost old gas is under contract to interstate pipelines, resulting in lower average costs of gas to interstate pipelines, as described above.[2] The difference between one pipeline's endowment of price-controlled gas, and thus its weighted average cost of gas, and another's, is the source of an advantage to the one with the lower average cost of gas when the two compete for incremental supplies of gas. The differential allows advantaged pipelines to bid the price of *deregulated* gas above the market-clearing level because high-priced gas can be averaged ("rolled in") with the low-cost gas and still be marketable.

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[1] The advantages of intrastate pipelines pre-NPGA had created a market-ordering problem of a similar kind. Instead of focusing on the nature of the problem and seeking to eliminate it, the NGPA merely reversed fields, substituting a new market-ordering problem for the old one.

[2] The difference in average gas costs is much more extensive, we think, than Louisiana Resources describes. The implication of its comments is that this difference exists *just* between interstate and intrastate pipelines. The implication is most likely wrong. The endowment of old gas is unevenly distributed among *all* pipelines, interstate and intrastate. It is probable that intrastate pipelines are more disadvantaged as a class than interstate pipelines. It is also probable that some interstate pipelines are substantially disadvantaged relative to other such pipelines.

This phenomenon can be illustrated by a very simple example. Assume that there are only two pipelines. Pipeline 1 and Pipeline 2 have gas supply contracts that provide each with 1,000 units of gas. Because Pipeline 1 got into the game when gas was still cheap, it has only one contract, which requires it to pay $1.00/unit. Pipeline 2 started later, and it has two contracts. One enables it to purchase 500 units of gas for $1.00/unit, and the other 500 units of gas for $2.00/unit. In all material respects, all of these contracts are identical except for price.

The result of these arrangements is that Pipeline 1 pays $1,000 for its 1,000 units of gas, while Pipeline 2 pays $1,500 for its 1,000 units. Their respective weighted average gas costs are $1.00/unit and $1.50/unit, and the 50-cent difference represents Pipeline 1's bidding advantage. Now assume that 1,000 units of gas are available for sale, and the alternative fuel price at the margin is $2.00, establishing the ceiling above which gas cannot be marketed. Pipeline 1 has the buying advantage since it can offer a maximum price of $3.00/unit for the gas. When it averages the cost with its gas already under contract, it can sell the gas at an average price of $2.00 and clear the market. Pipeline 2, however, can offer no more than $2.50/unit for the gas, because to offer a higher price would push its average gas cost above $2.00/unit, disabling it from clearing the market.

The real world is more complex than the example. However, the example is useful for two reasons. First, it illustrates how control of price-regulated gas creates competitive dislocations, and thus how one pipeline can be disadvantaged in purchasing natural gas supplies relative to another under the scheme of the NGPA. Secondly, it illustrates why the Commission is seeing requests by pipeline companies to include in their PGA accounts contract prices that clearly exceed market clearing levels.[3] Incidentally, this phenomenon also relates to the Commission's apparent witch-hunt under the rubric of Section 601(c)(2) in which pipelines are sought to be penalized on "fraud, abuse or similar grounds" for doing exactly what the NGPA impels them to do, and that which anyone with an iota of economic education could predict they, in their economic best interest, would do.

How does all of this relate to the incremental pricing rules? The answer is that those rules were adopted by Congress as a mechanism to reduce the magnitude of the market-ordering problem and also to shield certain classes of consumers from the higher costs of gas resulting from the NGPA. Louisiana Resources accurately describes what Congress sought to do, if not the track record and prospects of incremental pricing, as follows:

> Essentially, the market-determined cost determined by Congress resulted from the legislative determination that certain large-volume industrial customers would bear a disproportionate share of the higher gas costs paid by their pipeline suppliers for "new" gas supplies. As conceived by the Congress, the higher retail gas costs which would thus result to such customers would both encourage increased energy conservation by the customers so affected (thus reducing the demand on the pipeline for "new" gas), and discourage interstate pipelines from paying economically unjustified * * * prices for the "new" gas supplies that were acquired. Louisiana Resources Comments at 11 (footnotes omitted).

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[3] *See* Semiannual Purchased Gas Adjustment filed by Tennessee Gas Pipeline Company, Docket No. TA81-2-9-000 (PGA 81-2, IPR 81-2, DCA 81-2, R&D 81-2, LFUT 81-2) filed May 29, 1981. One of the company's contracts represented the purchase of deregulated gas at a price of $9.60/Mcf.

Problematically, however, incremental pricing is a failure. It will not accomplish either its shielding or its market-ordering goals, although for somewhat different reasons. Incremental pricing cannot accomplish its shielding objective because the number of nonexempt users is too small. Incremental pricing therefore burdens nonexempt users without significantly reducing the price paid by exempt users. In this connection, a change from a single-tier system to a three-tier system would do little if anything to increase the shielding effect, and whatever benefit did result would be purchased at too high a price in uneconomic investment and administrative complexity. We are statutorily bound, unfortunately, to implement incremental pricing, but we are also statutorily bound to implement it in the least disruptive way possible. There is clear and substantial record evidence in this proceeding to substantiate the proposition that a three-tier system will encourage substantial fuel switching, with correlative loss of markets to pipelines and imposition of fixed costs on exempt users that they would not otherwise be required to bear. For this reason particularly we are permanently adopting a single-tier alternative fuel price ceiling based on high-sulfur No. 6 fuel oil.

There are also more fundamental causes for incremental pricing's failure as a market-ordering device, causes that would not be eliminated simply by increasing the number of nonexempt users. Incremental pricing is a form of retail rate structure regulation that does in principle offer a partial solution to the market-ordering problems. It could restrain the pipelines, as Louisiana Resources points out, from bidding the unregulated price of gas above competitive market levels if it imposed a marginal-cost price on the pipeline's most price responsive customers. However, the incremental pricing scheme established by Title II of the NGPA cannot solve even this part of the market-ordering problem. The burner-tip price paid by nonexempt users is not directly related to the marginal cost of natural gas to the pipelines. Nor does Title II's distinction between nonexempt and exempt users correspond very closely to the distinction between price-responsive and price-unresponsive customers. Large boiler fuel users are generally considered to be the most important price-responsive category of natural gas users, and large boiler fuel users are in fact generally subject to incremental pricing if they are industrial firms. If they are electric utilities or agricultural users, however, they are exempt. Incremental pricing therefore leads to a higher price and lower consumption for industrial boiler fuel users, but a lower price and higher consumption for electric utility and agricultural boiler fuel users. An incremental pricing scheme based on such categories can favor some kinds of companies over others, but it is doubtful that it can contribute meaningfully to the alleviation of the market-ordering problems.

It is also clear that the incremental pricing scheme has no effect on the distribution of price controlled gas among the nation's pipelines. Furthermore, the unregulated field price confronted by the pipelines will vary widely even with incremental pricing. Thus the impact of partial deregulation will be unevenly distributed among both interstate and intrastate consumers depending solely on the fortuity of which pipeline serves them, and the retail rate regulation envisioned by incremental pricing will do little to even the burden.

Finally, there is a fundamental conflict between incremental pricing's two functions. Section 204(e) requires us to set the alternative fuel price at a level that will avoid excessive loss of nonexempt customers to the pipelines. This limitation is a logical adjunct to incremental pricing's shielding function. It is, however, inconsistent with incremental pricing's market-ordering function. It is precisely the danger of losing customers that could be expected to restrain pipelines from bidding for unregulated gas.

In connection with Louisiana Resources' comments, several observations should be made. First, Louisiana Resources suggests that the Commission seeks administratively to repeal incremental pricing, and that it should have given incremental pricing a "trial" to see if it worked. Louisiana Resources also suggests that the Commission take other, unspecified steps to mitigate the market-ordering problem if it adopts the rules, and that not to do so is to act in a discriminatory and capricious manner. The response is that the Commission is doing what Congress told the Commission to do if it found such necessary to avert a disaster to interstate consumers. To ask the Commission to give incremental pricing a "trial" in the face of probable massive, permanent fuel switching and the resulting imposition of heavy fixed costs on exempt consumers is like suggesting that the military test a bomb in a crowded city to see if it works. Furthermore, it is not the Commission's rule that is discriminatory, but the NGPA which merely reversed the pre-NGPA discrimination instead of seeking a more even-handed solution to the problem.

I emphathize deeply with the not inconsiderable problems faced by intrastate pipelines. The unfortunate interregional bickering that characterized the last legislative debate on natural gas policy obscured serious implications of intrastate dislocations in a cloud of rhetorical smoke. It ignored the fact that much primary industry upon which the rest of the country depends is served by intrastate pipelines. Ask Detroit, for example, about the shortage of plastics that could result from dislocations in the Louisiana-Texas petrochemical complex. Ask the rubber companies in Ohio the same question. There are other examples. Additionally, these dislocations can be predicted to occur on some interstate pipelines, whose customers could be faced with higher gas prices than they would face under total deregulation of the wellhead prices of natural gas.

The solution which Louisiana Resources asks the Commission to find can only be found by Congress and the new Administration. The choices, as I see them, are (i) regulation of all gas, (ii) an entitlements program, or (iii) complete deregulation of all gas prices. The first would be to enact as a solution what, in my view, is actually the problem. The second would be another exercise in corporate welfare that has no more prospect for success than the program devised for refiners. The third option has some hope for success if answers to numerous mechanical problems of implementation can be fashioned. A revised incremental pricing scheme could make some contribution to solving the problem, but will do nothing to prevent the uneven impact of partial deregulation. It appears that only complete deregulation offers a solution to the market-ordering problem.

Complete deregulation is not without its costs. Any honest debate over natural gas policy must begin with the recognition that decades of price controls have created a problem for which there is no easy solution. Any alternative will adversely affect the interests of many persons. This is true of complete deregulation, but it is also true of partial deregulation now projected to occur in January 1985. There is, and will continue to be, debate over the precise magnitude of the market-ordering problem that we will confront in the absence of legislative action. However, there is good reason to fear that it will be severely disruptive of both interstate and intrastate natural gas markets. Experience with deregulated Section 107 gas strongly suggests that the direct benefit of continued price controls on some categories of natural gas will go to producers of deregulated gas, through prices well above the level that would prevail under complete deregulation. For customers of some interstate pipelines, the high cost of deregulated gas will be offset by the pipelines' supply of low-cost deregulated gas. Customers of other

interstate pipelines and most intrastate pipelines will, however, pay more for natural gas than they would under complete deregulation. Possibly the average price of gas to all consumers will be lower under partial deregulation than under complete deregulation. Any benefit to consumers from this lower average price will, however, be at least partially offset by the inefficient allocation of the natural gas supply, as low-valued uses are served by some pipelines while elsewhere customers to whom the gas would be more valuable are priced out of the market simply because their pipeline has little price-controlled gas. The latter customers may include many of the nation's most important industrial users of natural gas, and the resulting disruption of their operations is unlikely to be confined to the companies concerned. Uncertainty, confusion, and delayed institutional responses are likely to further aggravate the market-ordering problem. In the end, the uneven impact of partial deregulation is likely to create a game in which many will lose and few will win. It is against that prospect that the costs of complete deregulation must be measured. Unfortunately, incremental pricing is no solution, whether the Commission adopts a one-tier rule or a two-tier rule.

C. M. Butler III,

[¶ 30,283]

46 F. R. 42260 (August 20, 1981)

18 CFR Part 154

[Docket No. RM78-23]

Procedures for Refund of Louisiana First Use Tax by Primary Pipelines—Notice of Effective Date

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of effective date of interim rule.

SUMMARY: On July 17, 1981, the Commission issued Order 10-D (46 FR 38681; July 29, 1981) which amended paragraph (h)(3) of 18 CFR 154.38, effective immediately, contingent upon approval by the Fifth Circuit Court of Appeals for leave to amend Order Nos. 10, 10-A, 10-B and 10-C. Order 10-D provides procedures for the refund by primary pipelines of the Louisiana First Use Tax found invalid by the Supreme Court. The Fifth Circuit granted the Commission's leave to amend on July 31, 1981 and Order 10-D is effective as of that date.

EFFECTIVE DATE: Order No. 10-D is effective as of July 31, 1981.

FOR FURTHER INFORMATION CONTACT:

Fredrick L. Jaffe, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8150, or

John Cameron, Office of the Solicitor, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8469.

Kenneth F. Plumb,
Secretary.

[¶ 30,284]

46 F. R. 42261 (August 20, 1981)

18 CFR Parts 157 and 260

[Order No. 168; RM 80-69]

Interstate Pipeline's Annual Report of Gas Supply: Form No. 15

Issued: August 14, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) revises Form No. 15, "Interstate Pipeline's Annual Report of Gas Supply," for forms filed by April 1, 1982. The revisions include reducing the number of data elements in the form.

clarifying accompanying instructions and definitions, changing the format of the statements and schedules in the form and revising the regulations which require the reporting of Form No. 15 data.

As a result of these changes, the respondent reporting requirements should be reduced by more than 50 percent.

DATE: The revisions are effective September 14, 1981 for the forms due April 1, 1982 and for the forms filed annually thereafter.

ADDRESS: Copies of Form No. 15 and the instructions for the form are available at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Wayne Thompson, Chief, Gas Supply Branch, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Room 4402–B, Washington, D.C. 20426, (202) 357–9077.

SUPPLEMENTARY INFORMATION:

In the matter of Interstate Pipeline's Annual Report of Gas Supply: Form No. 15.

The Federal Energy Regulatory Commission (Commission) revises Form No. 15,[1] "Interstate Pipeline's Annual Report of Gas Supply" (previously entitled, "Annual Report of Gas Supply for Certain Natural Gas Pipelines") and the related regulations at 18 CFR 157.14, 260.7 and 260.7a. These revisions are a part of the Commission's ongoing program to review and evaluate all of the data which are required by the Commission for its regulatory purposes and to eliminate unnecessary reporting requirements. The changes resulting from this rulemaking should reduce respondent burdens by more than 50 percent.

I. Background

A. Description and Uses of Form No. 15

Form No. 15 is prescribed in § 260.7 of the Commission's regulations, and is collected pursuant to the Commission's authority under section 10 of the Natural Gas Act (15 U.S.C. 717–717w).[2] The form prescribes information to be given on an annual basis concerning the total gas supply of each pipeline under the jurisdiction of the Commission.[3] The gas supply information includes a pipeline company's owned reserves, producer contracts for which the producer has received a certificate to sell the gas to the pipeline,[4] gas purchase contracts with other jurisdictional pipelines,[5] purchases of gas from foreign suppliers, purchases of Liquefied Natural Gas (LNG), Synthetic Natural Gas (SNG), coal gas, and short-term or other purchases over which the Commission has regulatory authority.

The data collected in Form No. 15 are used: (a) in considering gas supply issues in certificate applications and curtailment cases; (b) to perform depreciation analyses in rate cases; (c) to make determinations about new or increased sales of natural gas, extensions of facilities, or abandonment of service; and (d) as the basis for the annual publication, "Gas Supplies of Interstate Natural Gas Pipeline Companies."

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[1] Form No. 15 is not being printed by the Federal Register. Copies of Form No. 15 and the instructions for the form are available at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426.

[2] The authority under section 10 of the Natural Gas Act pertaining to the collection of annual and periodic or special reports was transferred to the Secretary of Energy under the Department of Energy Organization Act. The Secretary of Energy delegated this section 10 authority to the Commission in Delegation Order No. 0204–1 (October 1, 1977).

[3] Form No. 15 was initially promulgated in Order No. 279 (29 FR 4874, April 7, 1964). It has been revised four times prior to this rulemaking: Order No. 337 (32 FR 3292, February 25, 1967); Order No. 339 (35 FR 6962, May 1, 1970); Order No. 476 (38 FR 6810, March 13, 1973); and Order No. 546 (41 FR 9868, March 8, 1976).

[4] Under section 601 of the Natural Gas Policy Act (NGPA) (15 U.S.C. 3301–3432), producers are no longer required to obtain certificates for sales in certain instances.

[5] Under the NGPA, pipelines may also purchase gas from intrastate pipeline companies.

B. History of Proceedings

The proceedings to revise Form No. 15 in this docket were initiated by a Notice of Proposed Rulemaking issued on August 7, 1980 (45 FR 54082, August 14, 1980). The notice proposed changes to Form No. 15 to: (1) delete data elements which are no longer necessary to the Commission's regulatory functions, (2) make the form more concise, (3) clarify the instructions, (4) clarify and update the definitions, and (5) modify the magnetic tape procedures. The notice also proposed revisions to the Commission's regulations at §§ 260.7 and 260.7a to clarify those regulations and to reflect the changes proposed for the form.

The majority of commenters to the notice[6] favored the proposed deletions of data elements contained in the notice. However, comments also stated that the proposed requirements for data submission, as well as some of the proposed instructions and definitions, would *increase* reporting burdens. Finally, the commenters suggested that a conference between Commission staff and interested persons should be held to discuss various other clarifications and revisions to the form.

As a result of these comments, the Commission issued an Interim Rule of November 6, 1980 (45 FR 75192, November 14, 1980). This Interim Rule deleted those items proposed for elimination in the August Notice of Proposed Rulemaking. (*See* Interim Rule, pp. 7–10 and Attachment A.) These data were not therefore, required in the next filing of Form No. 15 (due April 1, 1981). The Interim Rule also provided for a series of informal public meetings at which further changes to the form were to be discussed.[7] At the meetings, several suggestions were offered for improving the format, instructions and definitions for the form.

A Revised Notice of Proposed Rulemaking was issued April 2, 1981 (46 FR 21189, April 9, 1981). That notice incorporated the deletions to Form No. 15 which were described in the November, 1980 Interim Rule. In addition, the Commission proposed several other changes to Form No. 15. (*See* Revised Notice of Proposed Rulemaking, pp. 7–16 and Attachment A.) Most of the proposed revisions were made as a result of suggestions made at the public meetings and in written comments.

The most important changes proposed in this second notice were to: (1) eliminate from Form No. 15 the reporting of detailed reservoir data in Schedule II and to combine Schedules II and III into a new Schedule II entitled, "Committed Reserves and Deliverability Estimates for All Supply Sources"; (2) clarify the definitions and instructions accompanying the form and revise them to conform with other changes proposed in the form itself; (3) change the field map requirement in the form so that maps would be required only if there had been a "substantial" revision in such maps since the last filing; (4) revise the form's magnetic tape layout and instructions to correspond with the printed form and its instructions; and (5) revise § 157.14(a)(10)(vi) of the Commission's regulations to provide for the reporting of certain information respecting individual reservoirs in the certificate application.[8]

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[6] Fourteen comments were filed by sixteen parties. Of these, twelve were from interstate pipelines which are required to file the form, one was from a natural gas user and one was from a gas industry trade association.

[7] After public notice, the meetings were held on December 2, 9, and 16, 1980. *See* Notice of Public Meetings, issued on November 17, 1980 (45 FR 77043, November 21, 1980); Notice of Agenda Change, in Public Meetings, issued December 3, 1980 (45 FR 81062, December 9, 1980); and Notice of Cancellation of Public Meetings and Reopening of Comment Period, issued December 24, 1980 (46 FR 1744, January 7, 1981). Copies of transcripts of the meetings area available in the Commission's Office of Public Information.

[8] The changes proposed in the revised notice for the regulations at §§ 260.7 and 260.7a were essentially the same as the revisions proposed in the August, 1980 Notice of Proposed Rulemaking. *See* Revised Notice of Proposed Rulemaking, pp. 14–15.

II. Summary and Analysis of Comments

In response to the Revised Notice of Proposed Rulemaking, the Commission received seven comments.[9] In general, the comments supported the proposed changes to Form No. 15. Additionally, INGAA and Transco estimated that the filing burden for Form No. 15 would be reduced by at least 90 percent, if the proposed changes were adopted.

The primary concern for many of the respondent pipeline companies and for INGAA was the proposed revision to § 157.14(a)(10)(vi) of the Commission's regulations requiring the reporting of individual reservoir data in an application for a certificate of public convenience and necessity. Columbia, El Paso, Northern and INGAA stated that the requirement to report reservoir data was simply "shifted" from the Form No. 15 to the certificate application. As a result, reporting burdens would probably be increased.

As a solution to this problem, the respondents offered three alternatives: (1) obtain information about individual reservoirs only through specific data requests; (2) require that individual reservoir data be reported either in Form No. 15 or in a certificate application, at the option of a respondent; or (3) require reports of field and reservoir data in certificate applications only as they pertain to new sources of natural gas or to sources in which there have been significant changes from the previously filed data.

The Commission has adopted the essence of the third alternative. The proposed requirement to report reservoir data as they pertain to "existing" supply sources has been eliminated from § 157.14(a)(10)(vi), and individual reservoir data are required only for *new* sources of supply not previously reported. This modification should cause no additional reporting burdens and will eliminate any potential burden attached to reports of data for existing supply sources.

In responses to the first of the other alternatives, the Commission believes that the reporting of these data is more appropriate in certificate applications than in response to specific requests. When new supply sources are at issue in a certificate application, the Commission must obtain certain information about such new sources before it can grant the application. In response to the other alternative, the Commission cannot grant the option of reporting individual reservoir data in either a Form No. 15 filing or in a certificate application because certificate applications are not usually filed at the same time as the Form No. 15. Thus, information in a certificate application does not relate to the same time period as a Form No. 15 filing. Because information about new supply sources is relevant to certificate applications, it should be prescribed for the same time frame as the other information in the application.

The only other problem area which was discussed by more than one commenter concerned the revisions to the magnetic tape instructions and layouts. Transco, Michigan Wisconsin and INGAA noted several areas where there was a lack of consistency between the magnetic tape instructions and layout and between the tape format and the printed form. They each offered suggestions to clarify the magnetic tape requirements and adapt the tape layouts and instructions to the printed form.

The Commission has changed the magnetic tape instructions and layout, where necessary, to correct errors and inconsistencies between tape instructions and layout and between the tape format and the printed format.

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[9] Five comments were submitted by natural gas pipeline companies—Columbia Gas Transmission Corporation (Columbia), El Paso Natural Gas Company (El Paso), Michigan Wisconsin Pipe Line Company (Michigan Wisconsin), Northern Natural Gas Company, Division of InterNorth Incorporated (Northern), and Transcontinental Gas Pipe Line Company (Transco); one by a natural gas trade association which represents major long distance gas companies subject to Commission jurisdiction—Interstate Natural Gas Association of America (INGAA); and one by a natural gas user—General Motors Corporation (General Motors).

El Paso proposed amending the definitions of "reserve additions" and "revisions" so that extensions to a pipeline company's proved area would be included in the definition of "reserve additions," rather than in "revisions" as the revised notice proposed. In support of this suggestion, El Paso claimed that the natural gas industry normally reports extensions as reserve additions.

In its August 1980 Notice of Proposed Rulemaking, the Commission had proposed to expressly except extensions from the category of revisions. However, some industry representatives suggested that the definition of "revisions" include extensions.[19] Given these diverse views, the Commission has decided to include extensions as part of revisions. This alternative, rather than that offered by El Paso, seems more in accordance with industry preference. Furthermore, any changes in reserve estimates (positive or negative) made during the report year as a result of new information, logically includes the enlargement of the proved area (extensions).

El Paso also requested that the filing sequence (order) of Schedule II be defined in the instructions in order to clarify the organization of that schedule.

The Commission believes that it could not impose upon respondents the requirement of a specific filing sequence for Schedule II reports. There is currently no uniformity among pipeline companies in their bookkeeping practices respecting supply source data. In many cases, pipelines run into different supply areas and reporting companies maintain different systems for each area. The requirement for a filing sequence would, therefore, create an unnecessary reporting burden upon such companies. Furthermore, the Commission does not need a specific filing sequence to effectively utilize the data reported in Schedule II because the code system used therein makes it possible for information to be sorted in every relevant category (*e.g.*, by State, field, company).

El Paso also stated that the requirement to report "Approximate Heating Value (in BTU)" (Schedule II) is superfluous and that, if it is required at all, the instructions should be clarified respecting the manner in which such calculation should be made.

The Commission has retained the requirement to report approximate heating value in Btu. This information was previously required in Schedule III of the form; however, Schedule III was combined with Schedule II with the elimination of individual reservoir reporting. This requirement provides the only estimates in Form No. 15 of recoverable reserves that are salable at a particular point, in Btu's, after plant processing or treating. The data are also useful to isolate any unusually low Btu reserves. The Commission notes that it requires only an *approximation* of gross heating value of salable gas in Btu's because variations are expected to occur over a year's time depending, for example, on reservoirs produced.

El Paso also requested clarification of the term "non-producing reservoirs" respecting the requirement to report the numbers of non-producing reservoirs and the remaining total dry gas in non-producing reservoirs (Schedule II). El Paso was not sure whether non-producing reservoirs related to a respondent's or the entire industry's interest in the reservoir.

In response to EL Paso, the Commission has specifically defined "Non-producing reservoir" in Form No. 15 as a "reservoir in which oil and/or gas proved reserves have been identified, but which did not produce during the report year to the owned or contracted interest of the reporting company regardless of the availability and/or operation of production, gathering or transportation facilities" (Definition No. 21).

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[19] At the December 9, 1980 meeting to discuss changes to Form No. 15, representatives of Natural Gas Pipeline Company of America, Tennessee Gas Pipeline Company, United Gas Pipe Line Company and INGAA suggested that "revisions" include extensions. *See* Transcript, at 74–78.

Finally, El Paso stated that the requirement to report "Group totals" in Schedule II is unclear and could result in "misuse" of data.

The Commission notes that it had already clarified the use of group totals in the revised notice. (*See* Revised Notice of Proposed Rulemaking, Attachment A in the instructions for Schedule II, Lines 206 to 226, columns (02) to (06). Following the instruction for Lines 206 to 221 is a sample Schedule II which includes an example for reporting group totals.)

Michigan Wisconsin expressed concern about the proposed requirement in the Gas Procurement Activity Statement for information from pending negotiations and agreements concerning anticipated gas supply additions. Michigan Wisconsin stated that it is essential that such negotiations remain confidential in order to protect their contract negotiations and the gas procurement process.

The Commission intended that only general information be reported respecting such negotiations. Accordingly, the instructions in the Gas Procurement Activity Statement have been clarified to require:

> * * * *a general statement concerning* current contract negotiations; producer option agreements; advance payment agreements; negotiations with foreign suppliers; construction of facilities to produce, or contracts for, supplies of LNG, SNG, or coal gas; or any other activity to add gas supplies. (Emphasis added.)

Michigan Wisconsin also stated that clarification was necessary respecting the definition and instructions for reporting underground natural gas storage reserves. In support of this view, Michigan Wisconsin argued that, in its case, natural gas in underground storage does not contribute to its annual gas supply and therefore could not be reported as part of the Annual Scheduled Volumes in Schedule II (lines 222–226).

The Commission agrees that clarification of this matter is necessary and has revised its instructions in Schedule I in accordance with a suggested amendment by Michigan Wisconsin to provide that gas in underground storage should be included in owned reserves. Schedule II instructions have been amended to provide that owned gas in underground storage may be reported by individual storage field or as a total source of supply. When underground storage gas is reported in this manner, the underground storage gas line items for Estimated Annual Scheduled Volumes (Schedule II, Lines 222 through 226) are to be left blank.

Northern objected to the Commission's continued requirement to attach field maps to Form No. 15. Northern insisted that the field map requirement was not of sufficient benefit to justify the undue burden placed upon companies that must file such maps.

The Commission will continue to require that maps be attached to Form No. 15. These maps are essential to the Commission's determination of field development and acreage dedication for individual fields. Because of the broad geographic areas covered by Form No. 15 filings, and the large number of respondents who file the form, it would be virtually impossible for the Commission to maintain reliable maps without the assistance of companies who file them regularly. Furthermore, the Commission proposed in the revised notice to eliminate the requirement to show reservoir outlines on each map and provided that previously-submitted maps need not be refiled unless "substantial revisions" have been made to the maps during the report year. As a result, the map filing burden could be greatly reduced. Northern was also the only commenter who filed objections to the map requirement. In light of its regulatory need for such maps, the Commission believes that this requirement is amply justified.

General Motors was the only natural gas user which filed comments in this proceeding. The comments it filed in the revised notice were similar to those which it filed in response to the August 1980 Notice of Proposed Rulemaking and to its application for rehearing of the November 1980 Interim Rule.[11] General Motors stated that the form provided important data on a regular basis respecting gas supply and future gas deliveries and that, any changes to the form could be detrimental to all gas consumers.

A specific topic of concern for General Motors was the proposed revision in Schedule I whereby annual requirements of natural gas would be reported for only one year instead of the twenty years previously required. General Motors stated that requirements estimates for at least ten years were necessary to the Commission for its assessment of the adequacy of the pipelines' future gas supplies. General Motors added that requirements estimates are used to evaluate the deliverability life of reserves and that such deliverability life is the most important measure of the adequacy of supply. Finally, General Motors alledged that pipeline companies would not suffer a significant increase in reporting burdens if they had to provide their requirements estimates for a ten-year period, because these data would be gathered in the course of a company's ordinary business planning.

The Commission believes that the annual requirements provision in the new Form No. 15 is sufficient for the determination of the adequacy of a pipeline company's gas supplies. This form is not designed to gather long-term requirements or supplies data; rather, its purpose is to demonstrate a pipeline company's gas supply posture as of a precise date—the end of the report year. Moreover, if long-term increases or decreases in requirements were projected and gauged against deliverability from "currently-owned" and contracted gas supplies, the wrong conclusion could be reached concerning a company's future. This is because a pipeline company will probably acquire additional gas supplies each year in varying amounts, to meet its future requirement. A single-point-in-time estimate of supply and requirements is the best way to calculate such indices as the reserve life index, the deliverability life and the ratio of reserves to production. Furthermore, the data respecting "anticipated future supply additions" are required to be reported in the Gas Procurement Activity Statement of Form No. 15.

The respondent's burden of reporting annual requirements projections for ten or even five years would vary from company to company. As mentioned above, because their supply situations change frequently, not all respondents to the form are able to prepare long-term estimates of requirements. Furthermore, changeable economic conditions, consumer conservation and fuel switching make it difficult for many companies to accurately estimate their requirements for periods beyond one year. Therefore reliable short-term estimates are far more valuable to the Commission than long-term "guesses". For the type of information to be gathered on the new Form No. 15, the imposition of such a reporting burden is, in our opinion, not warranted.

A second objection raised by General Motors went to the Commission's proposed deletion of information about curtailments from Schedule I of Form No. 15 because it is reported in FERC Form No. 16, "Report of Gas Supply and Requirements". General Motors stated that data respecting the curtailments forced upon pipeline companies by their suppliers are important to the understanding of data concerning purchases from other pipelines.

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[11] The application for rehearing of the Interim Rule was denied with respect to 1980 reports. The Commission, however, granted rehearing "solely for the purpose of further consideration with respect to all future reports." (*See* "Order Denying in Part and Granting in Part for Purposes of Further Consideration the Application for Rehearing of Interim Rule," issued January 7, 1981.) In formulating the final rule in this docket, the Commission considered the comments filed by General Motors in its application for rehearing and those filed in response to the revised notice and addressed those comments in the text of this rule.

Furthermore, General Motors claimed that, contrary to Commission statements, this information is *not* reported in the Form No. 16.

The Form No. 16 was revised by Order No. 86 on May 30, 1980 (Docket No. RM80-20, 45 *Fed. Reg.* 37812, June 5, 1980). As a part of the Form No. 16 revisions, the term "curtailment" was changed to "net deficiency or surplus" to better describe curtailment: the difference between the net available for sale from the pipeline and pipeline requirements. The *actual* net deficiency or surplus is required to be reported in Schedule I of Form No. 16 and the *projected* deficiency or surplus for the following year is required in Schedule V of that form. Thus, Form No. 16 actually prescribes greater detail with respect to curtailments than did the previous Form No. 15. Form No. 16 must also be filed twice a year, so the data are more current than Form No. 15 data. The Commission has deleted the curtailment requirement from Schedule I of Form No. 15 to eliminate a duplication of data and because more frequent reporting of curtailments is required in Form No. 16.

A third concern for General Motors related to the instructions in Schedule I requiring a company's estimate of deliveries from its suppliers. While the Revised Notice of Proposed Rulemaking provided that pipelines shall explain their assumptions concerning pipeline supplies in a footnote, General Motors said that the instructions must also require an explanation of the basis for estimates of future deliveries from their sources, after curtailment. Without such a requirement, General Motors argued, pipeline companies might report deliveries of full contract quantities, even if such volumes may not be received.

The Commission agrees with this comment and suggested revision. Therefore, the instructions in Schedule I have been clarified to provide that pipelines shall report volumes contracted to be purchased from interstate pipelines and other supply contracts and "explain in a footnote how this data was derived".

Finally, General Motors requested that pipelines be required to attach to Form No. 15 copies of all long-term gas supply and service estimates which have been given to persons outside of the company. The data would complement Form No. 15 projections based on known reserves, according to General Motors, and would provide the company's own best estimates of its future supply and demand posture. The requirement would allegedly impose no additional reporting burden and would encourage pipelines to report only their best estimates to public officials and to the public.

For the same reasons that annual requirements and supply data need not be reported, the Commission does not require long-term service estimates to be reported in the Form No. 15. Because the Commission does not prescribe long-term service estimates it will not, therefore, require the attachment of such estimates which have been given to persons outside of the company. The additional reporting burden resulting from this requirement could be considerable, if each pipeline company were required to file *every* estimate given to each customer, public official, investor and any other person. Such information is best collected in individual proceedings rather than in an annual filing which is made by all pipeline companies.

III. Summary of Changes to the Revised Notice of Proposed Rulemaking

The Commission has adopted the changes to Form No. 15 and to §§ 157.14, 260.7 and 260.7a of the regulations which were proposed in the Revised Notice of Proposed Rulemaking.[12] In addition, the Commission has incorporated certain suggestions from the comments to the revised notice, all of which have been discussed in detail in Part II of the preamble to this final rule. These changes are:

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[12] *See* Part I.B. of the preamble to this final rule for a discussion of the history of this proceeding.

(a) Addition of the general definition for "Non-producing Reservoir" (Definition No. 21);

(b) Clarification of the "Gas Procurement Activity Statement" to provide that only a "general statement" is required respecting current contract negotiations; producer option agreements; advance payment agreements; negotiations with foreign suppliers; construction of facilities to produce, or contracts for, supplies of LNG, SNG or coal gas; or any other activities to add gas supplies;

(c) Clarification of the instructions for Lines 101 and 102 of Schedule I to provide that gas in underground storage should be included in owned reserves;

(d) Clarification of the instructions for Lines 103 to 122 of Schedule I to require a footnote explanation of how volume scheduled data was derived with respect to "Other Supply Contracts and Interstate Pipeline Purchases;"

(e) Clarification of the instructions for Lines 201 to 205 of Schedule II to provide that owned gas in underground storage may be reported by individual storage field or as a total; and providing that Lines 222 to 226 which report "Estimated Annual Scheduled Volumes" are to be left blank when underground storage gas is reported by storage field or as a total;

(f) Correction and clarification of the magnetic tape layout and instructions to conform with the printed version of the form; and

(g) Revision of the regulations at § 157.14 to provide that reports of individual reservoir data in certificate applications are required only with respect to new sources of supply.

The Commission has made additional minor changes to the form in response to comments to the revised notice. These include the following:

(a) Instruction X of the General Instructions, regarding the resubmission of Form No. 15 has been revised, as suggested, to provide that the entire report and magnetic tape may be refiled when major changes warrant complete resubmission.

(b) The definition of "Certificate Requirement" (Definition No. 2) has been changed in response to a suggestion that it should specify whether "Total Certificate Requirement" should include current Commission approved curtailment plans or be independent of such plans. The definition has been revised to provide that the volume reported should be "without regard" to Commission approved curtailment plans.

Finally, the Commission has made certain non-substantive changes to the regulations at §§ 260.7 and 260.7a to clarify the requirements described therein.

IV. Public Procedure and Effective Date

The Office of Management and Budget (OMB) has not yet approved the revised Form No. 15 under the provisions of the Paperwork Reduction Act of 1980 (44 U.S.C. §§ 3501–3520). The Commission is, nonetheless, issuing this final rule so that the respondents who file the revised form will have sufficient time to reprogram their computers to report the data in the new format. These companies will then be able to meet the April 1, 1982 deadline for the submission of the revised Form No. 15. Upon receipt of OMB approval for the collection of Form No. 15 data, the Commission will issue a notice in the **Federal Register** which states that such approval has been received.

The changes in this order will be effective on September 14, 1981, for reports to be filed on or before April 1, 1982 and for reports filed thereafter.

(Natural Gas Act, 15 U.S.C. 717–717w; Natural Gas Policy Act, 15 U.S.C. 3301–3432; Department of Energy Organization Act; 42 U.S.C. 7101–7352; E.O. 12009, 3 CFR 142)

In consideration of the foregoing, the Commission amends Form No. 15 and Parts 157 and 260 of Chapter I, Title 18 of the Code of Federal Regulations as set forth below.

By the Commission. Commissioner Hughes dissented with a separate statement attached.

Kenneth F. Plumb,
Secretary.

[¶ 30,285]

46 F. R. 45599 (September 14, 1981)

18 CFR Part 270

Standard for Determining Btu Content of Natural Gas; Partial Stay of Final Rule

AGENCY: Federal Energy Regulatory Commission.

ACTION: Order granting partial stay of final rule.

SUMMARY: The Federal Energy Regulatory Commission stays, pending further order, the effect of Order No. 93 (Docket No. RM80-33; 45 FR 49077; July 23, 1980) and Order No. 93-A (46 FR 24537; May 1, 1981) insofar as they concluded that the standard they prescribed for determining the Btu content of natural gas codified at 18 CFR 270.204 was in effect from December 1, 1978, to April 24, 1981. The order is subject to the approval of the United States Court of Appeals for the District of Columbia.

DATES: FERC will publish another document in the Federal Register announcing the effective date of the stay if the U.S. Court of Appeals for the District of Columbia approves of this order.

Section 270.204 shall remain effective as to all sales which occurred after April 24, 1981.

FOR FURTHER INFORMATION CONTACT: Teresa Ponder, Office of General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357-8151.

SUPPLEMENTARY INFORMATION: In the matter of final rules for Part 270, Subpart B, §§ 270.201, 270.202, and 270.204; Order Granting Partial Stay of Order Nos. 93 and 93-A Pending Further Order (Docket No. RM80-33).

Issued August 20, 1981.

On July 16, 1980, the Commission issued Order No. 93 (Docket No. RM80-33; 45 FR 49077; July 23, 1980) amending and issuing as final rules the regulation in 18 CFR 270.204 relating to the standard for determining the Btu content of natural gas. On April 24, 1981, the Commission issued Order No. 93-A, entitled "Order Denying Rehearing and Clarifying Order No. 93" (46 FR 24537; May 1, 1981). On July 22, 1981, El Paso Natural Gas Company filed a petition requesting full or partial stay of Order Nos. 93 and 93-A.

Order No. 93-A stated that the measuring standard prescribed in Order No. 93 took effect on December 1, 1978. We wish to reconsider that conclusion. Many pipelines have not yet paid all sums which would be due on the basis of that effective date. To that extent, we wish to preserve the status quo pending reconsideration of the question of the effective date.[1]

The Commission Orders

Order Nos. 93 and 93-A are stayed, pending further order, insofar as they concluded that the standard they prescribed for determining Btu content of natural gas was in effect from December 1, 1978, to April 24, 1981 (the date Order No. 93-A was issued). This order is subject to the approval of the United States Court of Appeals for the District of Columbia Circuit.

By the Commission.

Kenneth F. Plumb,
Secretary.

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[1] Should this reconsideration produce a different conclusion as to the effective date, we will make appropriate adjustments to relieve those who already paid in whole or in part.

[¶ 30,286]

46 F. R. 46900 (September 23, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Mississippi—2; Order No. 175)]

High-Cost Gas Produced From Tight Formations; Mississippi; Final Rule

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the State Oil and Gas Board of Mississippi that the Rea Sand of the Mississippian Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective September 18, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Walter Lawson (202) 357-8556.

The Commission hereby amends § 271.703(d) of its regulations to include the Rea Sand of the Mississippian Formation in Mississippi as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued May 18, 1981 (46 FR 27963, May 22, 1981) [1] based on a recommendation by the State Oil and Gas Board of Mississippi (Mississippi) in accordance with § 271.703(c), that the Rea Sand in the Mississippian Formation be designated as a tight formation.

Evidence submitted by Mississippi supports its assertion that the Rea Sand meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Mississippi recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, (42 U.S.C. 7101 *et seq.*); Natural Gas Policy Act of 1978 (15 U.S.C. 3301-3342); Administrative Procedure Act, (5 U.S.C. 553).)

For the reasons stated herein, Part 271 of Subchapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective September 18, 1981.

By the Commission.

Kenneth F. Plumb,

Secretary.

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[1] Comments were invited and none were received. No party requested a public hearing and no hearing was held.

[¶ 30,287]

46 F. R. 46901 (September 23, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Mississippi—1); Order No. 174]

High-Cost Gas Produced From Tight Formations; Mississippi; Final Rule

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the State Oil and Gas Board of Mississippi that the Upper Hosston Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective September 18, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Walter Lawson, (202) 357-8556.

The Commission hereby amends § 271.703(d) of its regulations to include the Upper Hosston Formation in Mississippi as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued April 1, 1981 (46 FR 20683, April 7, 1981)[1] based on a recommendation by the State Oil and Gas Board of Mississippi (Mississippi) in accordance with § 271.703(c), that the Upper Hosston Formation be designated as a tight formation.

Evidence submitted by Mississippi supports its assertion that the Upper Hosston Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Mississippi recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices be made available immediately. The need to make incentive prices immediately available establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, (42 U.S.C. 7101 *et. seq.*); Natural Gas Policy Act of 1978, (15 U.S.C. 3301-3342); Administrative Procedure Act, (5 U.S.C. 553))

For the reasons stated herein, Part 271 of Subchapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective September 18, 1981.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,288]

46 F. R. 46901 (September 23, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Texas—10); (Order No. 173)]

High-Cost Gas Produced From Tight Formations; Texas; Final Rule

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which

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[1] Comments were invited and none were received. No party requested a public hearing and no hearing was held.

may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Railroad Commission in Texas that the Edwards Limestone Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective September 18, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8307, or Walter Lawson, (202) 357–8556.

The Commission hereby amends § 271.703(d) of its regulations to include the Edwards Limestone in Texas as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued May 18, 1981 (46 FR 27964, May 22, 1981)[1] based on a recommendation by the Railroad Commission of Texas (Texas) in accordance with § 271.703(c) that the Edwards Limestone Formation be designated as a tight formation.

Evidence submitted by Texas and the commenters supports Texas' assertion that the Edwards Limestone Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Texas recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices be made available immediately. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act (42 U.S.C. 7101 *et seq.*); Natural Gas Policy Act of 1978 (15 U.S.C. 3301–3342); Administrative Procedure Act (5 U.S.C. 553))

For the reasons stated herein, Part 271 of Subchapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective September 18, 1981.

By the Commission

Kenneth F. Plumb,

Secretary.

[¶ 30,289]

46 F. R. 46902 (September 23, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Wyoming—7); Order No. 172]

High-Cost Gas Produced From Tight Formations; Wyoming; Final Rule

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Wyoming Oil and Gas Conservation Commission that the Frontier Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective September 18, 1981.

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[1] Comments were invited and two favorable comments were received. No party requested a public hearing and no hearing was held.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8307, or Victor Zabel, (202) 357–8616.

The Commission hereby amends § 271.703(d) of its regulations to include the Frontier Formation in Wyoming as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued June 18, 1981 (46 FR 32597, June 24, 1981)[1] based on a recommendation by the Wyoming Oil and Gas Conservation Commission (Wyoming) in accordance with § 271.703(c) that the Frontier Formation be designated as a tight formation.

Evidence submitted by Wyoming supports its assertion that the Frontier Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Wyoming recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, (42 U.S.C. 7101 *et seq.*); Natural Gas Policy Act of 1978, (15 U.S.C. 3301–3342); Administrative Procedure Act, (5 U.S.C. 553))

For the reason stated herein, Part 271 of Subchapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective September 18, 1981.

By the Commission.

Kenneth F. Plumb,
Secretary.

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[1] Comments were invited and one comment supporting the recommendation was received. No party requested a public hearing and no hearing was held.

[¶ 30,290]

46 F. R. 46903 (September 23, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Wyoming-5); Order No. 170]

High-Cost Gas Produced From Tight Formations, Wyoming; Final Rule

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Wyoming Oil and Gas Conservation Commission that the Frontier Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective September 18, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8307, or Victor Zabel, (202) 357–8616.

The Commission hereby amends § 271.703(d) of its regulations to include the Frontier Formation in Wyoming as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued June 16, 1981 (46 FR 32270, June 22, 1981)[1] based on a recommendation by the Wyoming Oil and Gas Conservation Commission (Wyoming) in accordance with

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[1] Comments were invited and one comment supporting the recommendation was received. No party requested a public hearing and no hearing was held.

§ 271.703(c) that the Frontier Formation be designated as a tight formation.

Evidence submitted by Wyoming supports its assertion that the Frontier Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Wyoming recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, (42 U.S.C. 7101 *et seq.*); Natural Gas Policy Act of 1978, (15 U.S.C. 3301–3342); Administrative Procedure Act, (5 U.S.C. 553.))

For the reasons stated herein, Part 271 of Subchapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective September 18, 1981.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,291]

46 F. R. 46903 (September 23, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Wyoming—6); Order No. 171]

High-Cost Gas Produced From Tight Formations; Wyoming; Final Rule

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Wyoming Oil and Gas Conservation Commission that the Bear River Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective September 18, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8307, or Victor Zabel, (202) 357–8616.

The Commission hereby amends § 271.703(d) of its regulations to include the Bear River Formation in Wyoming as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued June 18, 1981 (46 FR 32596, June 24, 1981)[1] based on a recommendation by the Wyoming Oil and Gas Conservation Commission (Wyoming) in accordance with § 271.703(c) that the Bear River Formation be designated as a tight formation.

Evidence submitted by Wyoming supports its assertion that the Bear River Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Wyoming recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

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[1] Comments were invited and one comment supporting the recommendation was received. No party requested a public hearing and no hearing was held.

(Department of Energy Organization Act, (42 U.S.C. 7101 *et seq.*); Natural Gas Policy Act of 1978, (15 U.S.C. 3301–3342); Administrative Procedure Act, (5 U.S.C. 553))

For the reasons stated herein, Part 271 of Subchapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective September 18, 1981.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,292]

46 F. R. 46904 (September 23, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Utah-2); Order No. 169]

High-Cost Gas Produced From Tight Formations; Utah; Final Rule

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the State of Utah Board of Oil, Gas and Mining that the Mancos "B" Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective September 18, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8307, or Victor Zabel, (202) 357–8616.

The Commission hereby amends § 271.703(d) of its regulations to include the Mancos "B" Formation in Utah as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by Director, OPPR, issued June 5, 1981 (46 FR 30833, June 11, 1981) [1] based on a Oil, Gas and Mining (Utah) in accordance with § 271.703(c) that the Mancos "B" Formation be designated as a tight formation.

Evidence submitted by Utah supports its assertion that the Mancos "B" Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Utah recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, (42 U.S.C. 7101 *et seq.*); Natural Gas Policy Act of 1978, (15 U.S.C. 3301–3342); Administrative Procedure Act, (5 U.S.C. 553))

For the reasons stated herein, Part 271 of Subchapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective September 18, 1981.

By the Commission.

Kenneth F. Plumb,
Secretary.

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[1] Comments were invited and one comment supporting the recommendation was received. No party requested a public hearing and no hearing was held.

[¶ 30,293]

46 F. R. 50064 (October 9, 1981)

18 CFR Part 282

[Docket No. RM81-27]

Incremental Pricing: Adoption of Single-Tier Alternative Fuel Price Ceiling; Effective Date

October 5, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of effective date.

SUMMARY: On July 24, 1981, the Federal Energy Regulatory Commission (Commission) issued a rule (46 FR 38912, July 30, 1981) under Title II of the Natural Gas Policy Act of 1978 (NGPA) amending its regulations at 18 CFR Part 282. The rule provides a permanent exemption, for all facilities subject to incremental pricing under Title II, from the alternative fuel price ceiling based on the cost of No. 2 fuel oil. In so doing, the rule establishes a single-tier alternative fuel price ceiling for such facilities, based on the cost of high-sulfur No. 6 fuel oil.

The rule was transmitted to the Congress for review as required by section 206(d) of the NGPA. During the period for Congressional review set forth in section 507(b) of the NGPA, neither House disapproved the submittal. This document confirms that the exemptive rule thus became effective October 3, 1981, the day following expiration of the review period.

EFFECTIVE DATE: October 3, 1981.

FOR FURTHER INFORMATION CONTACT:

Thomas P. Gross, Federal Energy Regulatory Commission, 825 North Capital Street, N.E., Washington, D.C. 20426, (202) 357-8171

Carol M. Lane, Federal Energy Regulatory Commission 825 North Capital Street, N.E., Washington, D.C. 20426, (202) 357-8511

Kenneth F. Plumb,
Secretary.

[¶ 30,294]

46 F. R. 48179 (October 1, 1981)

18 CFR Part 274

[Docket No. RM81-44; Order No. 176]

Identification of Jurisdictional Agencies

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) amends 18 CFR 274.501, which identifies the State and Federal agencies from

which well category determinations must be obtained under the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3301–3432). Section 503 of the NGPA provides that Federal and State agencies having regulatory jurisdiction with respect to the production of natural gas are authorized to make the initial determinations that gas qualifies under sections 102, 103, 107, and 108. Section 274.501 of the Commission's regulations lists the names and addresses of the appropriate jurisdictional agencies. The United States Department of Energy, the United States Geological Survey and the North Dakota Geological Survey have notified the Commission of a change in jurisdiction over specific natural gas production. The Commission now amends § 274.501(a)(2) to reflect those changes.

DATES: Effective date: September 23, 1981.

FOR FURTHER INFORMATION CONTACT: Thomas Hirsch, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357–8511.

SUPPLEMENTARY INFORMATION:

Issued: September 23, 1981.

By this rule, the Federal Energy Regulatory Commission (Commission) amends § 274.501, which identifies the State and Federal agencies from which well category determinations must be obtained under the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3301–3432). Section 503 of the NGPA provides that Federal and State agencies having regulatory jurisdiction with respect to the production of natural gas are authorized to make the initial determinations that gas qualifies under sections 102, 103, 107, and 108. Section 274.501 lists the names and addresses of the appropriate jurisdictional agencies. When a jurisdictional agency notifies the Commission of a change of jurisdiction over specific natural gas production, the change is reflected in § 274.501(a)(2) to provide current information to the public. The Commission now amends § 274.501(a)(2) to reflect changes submitted by the United States Department of Energy (DOE), the United States Geological Survey (USGS) and the North Dakota Geological Survey.

On March 28, 1980, the Commission received notice from DOE [1] that it was responsible for making well category determinations on certain Naval Petroleum Reserves.[2] On September 15, 1980, the Commission received notice from the USGS that its Central Region of the USGS Conservation Division located in Denver, Colorado, was the jurisdictional agency for Federal and Indian lands in the states of Colorado, Iowa, Kansas, Missouri, Nebraska and Utah. Also, on June 18, 1981, the North Dakota Geological Survey notified the Commission that effective July 1, 1981, the Industrial Commission would be the jurisdictional agency for lands other than federal lands for the state of North Dakota. Section 274.501(a)(2) is amended herein to reflect these changes.

Publication of a notice of proposed rulemaking and opportunity for public comment under section 553 (b) and (c) of the Administrative Procedure Act (5 U.S.C. 553) is unnecessary because the amendments simply inform the public of the identity and location of jurisdictional agencies. For the same reason, the 30 day publication prior to the effective date, otherwise required under section 553(d), is also unnecessary.

(Natural Gas Act, as amended, 15 U.S.C. 717–717w; Department of Energy Organization Act, 42 U.S.C. 7101–7352; Natural Gas Policy Act of 1978, 15 U.S.C.

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[1] See section 307 of DOE Organization Act. The Department of Energy's report of determination process, filed under § 274.105(a) was received by the Commission on March 28, 1980, and notice of receipt of the report was issued on May 1, 1980.

[2] Naval Petroleum Reserve No. 1 (Elk Hills, California), Naval Petroleum Reserve No. 2 (Buena Vista, California), Naval Petroleum Reserve No. 3 (Teapot Dome, Wyoming).

3301–3432; Administrative Procedure Act, 5 U.S.C. 553)

For reasons stated herein, Part 274 of Subchapter H, Title 18, Code of Federal Regulations, is amended as set forth below, effective September 23, 1981.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,295]

46 F. R. 50055 (October 9, 1981)

18 CFR Parts 8 and 141

[Docket No. RM81-36]

Licensed Hydropower Development Recreation Report: FERC Form No. 80; Revision

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) revises Form No. 80, "Licensed Hydropower Development Recreation Report" and the related regulations at 18 CFR 8.11 and 141.14. Form No. 80 collects information on a biennial basis concerning recreational opportunities and facilities at developments within hydroelectric projects licensed by the Commission.

The elements in the form are consolidated, simplified, and clarified and the form is reduced in size by approximately 60 percent. The revisions to Form No. 80 are part of the Commission's ongoing program to eliminate reporting requirements that are not necessary to the Commission's performance of its regulatory responsibilities and to reduce the burden of filing required information with the Commission.

DATE: The revisions are effective October 29, 1981.

ADDRESSES: Copies of the Form No. 80 are available at the Federal Energy Regulatory Commission, Office of Public Information, 825 North Capitol Street, NE., Room 1000, Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:
John O. Young, Office of Electric Power Regulation, 825 North Capitol Street NE., Room 308RB, Washington, D.C. 20426, (202) 376–4312.

SUPPLEMENTARY INFORMATION:

I. Introduction

The Federal Energy Regulatory Commission (Commission) revises the Form No. 80,[1] "Licensed Hydropower Development Recreation Report") and the related regulations at 18 CFR 8.11 and 141.14. The revisions are part of the Commission's ongoing program to review and evaluate all of its reporting requirements and to eliminate those requirements which pose unnecessary reporting burdens and are unnecessary to the performance of the Commission's regulatory responsibilities. As a result of this rulemaking, the number of data elements in the form are reduced by approximately 60 percent. This should result in a net decrease of 75 percent in the time it takes for respondents to collect, record and submit data for each filing of the form. Thus, only 10 hours should be needed to complete the form, instead of the 40 hours previously needed.

II. Description and Uses of Form No. 80

Form No. 80 gathers information about recreational facilities and recreational opportunities at developments within hydroelectric projects [2] licensed by the Commission under the Federal Power Act.[3] These data are used to determine whether the public's need for water-based recreational facilities is being met by the licensees of such projects and whether additional efforts should be made to meet current and future recreational needs.

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[1] Form No. 80 (Attachments A and B) is not being printed by the Federal Register. Copies of the Form No. 80, including all instructions to the form are available at the Commission's Office of Public Information, 825 North Capitol Street, NE., Room 1000, Washington, D.C. 20426.

[2] For purposes of Form No. 80, each development within a project contains a reservoir, or a generating station and its specifically-related waterways.

[3] According to the provisions of the Department of Energy Organization Act (DOE Act), the Commission is authorized to issue licenses for hydropower projects under sections 4 and 15 of the Federal Power Act (16 U.S.C. 797, 808). Also according to the DOE Act, the Commission collects Form No. 80 data under section 304 of the Federal Power Act (16 U.S.C. 825c).

The Form No. 80 is currently filed by about 160 hydroelectric project licensees. The form is required to be submitted every other year and it collects data only for the calendar year immediately preceding the year in which it is filed.

III. Summary of Proposed Changes

The Notice of Proposed Rulemaking to revise Form No. 80 (notice) was issued on July 2, 1981 (46 FR 35298, July 8, 1981). By that notice, the Commission proposed to completely redesign Form No. 80 to consolidate and clarify necessary data requirements, eliminate unnecessary elements and update certain of the reporting requirements. The notice also stated that the instructions would be revised to provide that only the 1981 filing or an initial (first-time) filing of the revised Form No. 80 would have to be a complete filing; after 1981, the form would be preprinted by the Commission so that respondents would have only to "change, delete or add to" the previously submitted information as necessary.

With respect to the Commission's regulations that require the filing of Form No. 80, the most significant revisions in the notice were proposed for § 8.11. That section would reflect the changes to the instructions whereby project licensees would complete the Form No. 80 in its entirety only for the 1981 filing or for initial filings of the form. Subsequent filings would have to be completed only to the extent needed to update previously-submitted data. Another revision was proposed for § 8.11 to reflect changes in other portions of the Commission's regulations pursuant to requirements in the Public Utility Regulatory Policies Act.[4]

IV. Summary and Analysis of Comments

In response to the Notice of Proposed Rulemaking, the Commission received comments from six electric utility companies and one association representing the majority of investor-owned electric utility companies.[5] All of the comments supported the Commission's efforts to reduce the amount of data collected in the form and decrease the amount of preparation time needed to complete Form No. 80. One commenter stated that the proposed revisions to delete approximately 60 percent of the data elements from the current form should result in a 75 percent decrease in the time required to complete the form. Another commenter noted that the reduction and simplification of the reporting requirements in the Form No. 80 would also benefit its customers through cost savings.

Two commenters offered specific suggestions to further revise the Form No. 80 requirements. Both of these commenters were concerned about the proposed change in the filing date for the form from November 30 of each odd-numbered year to February 28 of each odd-numbered year.[6] Because the form reports information for the previous calendar year, only two months would be available to collect and synthesize this information before it had to be filed. The commenters argued that this would present certain difficulties for respondent companies, including the burden of compiling the data for the Form No. 80 at the same time that other reports must be prepared for the Commission and for other agencies. One of the commenters suggested an April 1st deadline, as an alternative. The other commenter preferred the current November 30th filing date, but added that May 31st may also be appropriate.

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[4] For a complete discussion of the proposed revisions to Form No. 80, see Part II of the Notice of Proposed Rulemaking.

[5] American Electric Power Service Corporation (AEP), Georgia Power Company, Northeast Utilities (representing the Connecticut Light and Power Company, the Hartford Electric Light Company, Western Massachusetts Electric Company, Holyoke Water Power Company, Northeast Utilities Service Company and Northeast Nuclear Energy Company), Southern California Edison Company, Utah Power and Light Company, the Washington Water Power Company, and Edison Electric Institute (EEI).

[6] The Notice of Proposed Rulemaking required that the initial submissions of the revised Form No. 80 be made by November 30, 1981. Subsequent filings of this biennial report would be required by February 28th of each odd-numbered year.

In response to these comments, the Commission has changed the filing date for submitting the Form No. 80 to April 1st of each odd-numbered year. This new date will be effective for reports due subsequent to the 1981 filing (*i.e.*, 1983, 1985, etc.). The Commission believes that the additional month will provide licensees ample time to accumulate, record and submit the data on the form, and will not adversely affect the timeliness of the information reported for the previous calendar year. Furthermore, the reductions in the information required in the Form No. 80 as a result of this rulemaking and the preprinting of the form by the Commission will greatly reduce the amount of time needed to prepare the form.

Although it was not specifically discussed in the comments, the Commission further revises the proposed requirement for filing 1981 reports. Instead of requiring that all licensees must complete the Form No. 80 in its entirety for the 1981 filing, the Commission will send to licensees who currently file the form, copies of a preprinted version of the last report which they submitted to the Commission (1979); this information will already be converted to the format of the revised Form No. 80. These licensees will have only to correct the previously-filed data, as necessary. The preprinted forms should reduce, somewhat, the amount of time needed by respondents to complete the forms for the 1981 filing. As provided in the notice, the Commission will also preprint the forms for filings that are due subsequent to 1981 so that respondents who filed in 1981 will only have to alter the information in the form as necessary, to correct such previously-filed data.

Instead of changing the filing date, one of the commenters said the Commission should provide that, when it is a burden to file the specific data, early filings and estimated data will be accepted, if they are believed to be essentially similar to information that would be obtained at the closing date.

The Commission will accept early filings of the forms (*i.e.*, prior to the due date), if such forms contain an accurate report of the required data. Thus, the reported information may be for a period ending before December 31st of an even-numbered year, so long as that information completely satisfies the requirements in the form. To clarify this point the Commission has amended the *General Information* portion of the form to provide that the report shall contain "information compiled during" an even-numbered calendar year.

The Commission has also amended the *General Instructions* in the form to provide that reasonable estimates of required data will be accepted if actual information is not available at the time of the filing. Such estimated data may include information that tends to vary from report to report, such as the number of annual visits to the development (Item 26) or annual recreational costs for the development (Item 27 (a)). Actual information, however, is required for data that varies little from report to report, such as the number of boat ramps within the development (Item 33—Definition 11) or the existing total acreage or mileage at the development for the facilities identified in the report (Item 39).

One commenter identified certain definitions and instructions that could be further revised or clarified. One such definition was "Code 66—*Hunting Areas*", which is defined as, "[p]ublic areas designated for hunting." The commenter said this definition should be clarified to exclude private lands located within, and adjoining, the project boundaries which are open to hunters because no legal obligation requires the private owners to provide such information to the licensee. For the same reason, the commenter said that Item Nos. 33 through 42 of the instructions, which refer to facilities within and adjacent to the development boundary, should be revised to exclude private recreational facilities within and adjoining these boundaries.

The Commission will require reports of facilities within the development that are operated by entities other than the licensee because the Commission needs information about all of the facilities at a development in the performance of its regulatory functions. Furthermore, the Commission believes that each licensee can require information about hunting areas or other recreational facilities operated by others within the development. The privately-owned facilities, including those that are adjacent to the development, may affect the type and amount of recreational activities within the development. The Commission uses this information to make a reasonable assessment of the recreational needs for the development. The Commission notes, however, that this information may be estimated if actual data are not available at the time of filing the Form No. 80.

To clarify these provisions, the Commission has revised the definition of "*Hunting Areas*" to read, "Public or private areas open to the general public for the purpose of hunting." Thus, in Items 33–40, each licensee must report all hunting areas which it provides within the development and also in places that are adjacent to the development, and all hunting areas within the development that are operated by others, including private owners. In Items 41–42, the licensee must report those hunting areas that are outside but adjacent to the development and operated by entities other than the licensee, including private owners.

In order to clarify the requirements for reporting all recreational facilities, the Commission has amended the Note that refers to Items 33–40 to provide that, the facilities within the development to which these items apply are "land- and water-based facilities provided by licensees or others, including privately-owned facilities."[7] The Commission has also amended Item 41 to provide that each of the facilities outside of the development is one that "is owned and operated by entities other than the licensee, 'including privately-owned facilities.' " (Emphasis added).

The commenter also recommended clarification of "Code 72—*Motels, Hotels and Lodges*", which is defined, in part, as "[o]vernight lodging establishments for transient use in and around the development." According to the comments, a quantitative definition for the phrase, "around the development" is needed so that such establishments can be inventoried. The commenter requested clarification as to whether "around the development" also applied to *"Code 70—Year-Round Homes", "Code 71—Seasonal Cottages"* and *"Code 80—Trailer Parks."*

In response to this comment, the Commission has amended the definition for *Motels, Hotels and Lodges* to read as follows: "Overnight lodging establishments open to the general public for transient use that are within the development (or in the case of Part II, Item 41, that are adjacent to, or within the reasonable vicinity of the development). The category includes, as one unit, each group of rental cabins that are generally rented or used on daily basis. This category does not include *Code 70—Year-Round Homes, Code 71—Seasonal Cottages,* or *Code 80—Trailer Parks.*" Under the definition of Motels, Hotels and Lodges, licensees must report the motels, hotels and lodges that are within the development and also those outside of the development that would *reasonably* provide overnight accommodations for recreational visitors to a development, even though such facilities may not necessarily be adjacent to the development. With respect to year-round homes, seasonal cottages or trailer parks, however, the Commission only requires information about licensee-operated facilities or facilities operated by others that are either within, or adjacent to, the development.

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[7] The Commission has also corrected this note to specify that the licensee-provided facilities for which data are required include those that are "adjacent" to the development.

The Commission has also clarified *Code 20—Trails* to eliminate the phrase "in or around a development." Such trails are either within or adjacent to a development (or partially within and partially adjacent to a development); thus, the instructions at Items 33–40 and 41–42 elicit the necessary information without the "in and around" qualification.

The commenter criticized Item 27(a), which requires a report of recreational costs for the previous year because that instruction did not specify whether the costs are maintenance costs only or include costs associated with any development since the last report. The Commission has revised Item 27(a) to require the report of recreational operation and maintenance costs.

The commenter also recommended that Items 27(a), 27(b), 28, 29 and 30 of the instructions be clarified to produce a consistent data base.[8] The commenter said that those items should be revised to exclude information about the costs, revenues and future developments of private developers who operate within a project but operate independently of a licensee. This information is not provided to the licensee, according to the comment.

The Commission has clarified the instructions at Items 27 (a) and (b) to require information only with respect to the licensee's costs and revenues because the Commission needs such information only as it pertains to the licensee's facilities. Furthermore, licensees could not be expected to obtain such information from private entities operating within the development. However, the Commission will require information in Items 28, 29 and 30 concerning the development of recreational facilities by private entities within the development. The Commission has clarified the instructions in Item 28 to provide that reports for Items 28 and 29 shall include "privately-owned facilities." The Commission requires this information from licensees to properly assess the growth possibilities at a development. Also, licensees can require such data from any private entity operating in the development. In addition, the Commission has clarified Item 30 to require the name of any cooperating agency or entity "assisting in the development of" such planned recreational facilities.

The phrase "within or contiguous to the development (project) boundary" has been deleted from Item 33[9] because it duplicates the requirement in the Note preceding Item 33. The Commission has also added the following provision to Item 33: "Do Not Use Codes 70, 71, 72, 73, 80 and 81." These codes are excluded from Items 33 through 40 because they are reported in adequate detail elsewhere in the form and need not be duplicated here.

V. Summary of Changes To Form No. 80 Requirements

The Commission adopts the revisions to Form No. 80 and to the regulations at §§ 8.11 and 141.14 that were proposed in the Notice of Proposed Rulemaking. The Commission also makes further changes to the form and the regulations at § 8.11 as a result of the comments received in response to the notice and to further clarify the form or its instructions.

The more important of these further changes to the form are as follows:

(1) The *General Information* section has been amended to provide that the filing date for forms submitted subsequent to 1981 is April 1st of each odd-numbered year.

(2) The *General Information* section has been changed to provide that reports must include "information

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[8] According to the notice, Item 27(b) requires information on the revenues and charges from a previous year, Items 28 and 29 require data on facilities to be developed in the next two years and Item 30 requires the name of any cooperating agency or entity providing financial assistance for the development of the facilities identified in Items 28 and 29.

[9] According to the notice, Item 33 requires the identification of each recreational facility within or contiguous to the development and all facilities planned for the future.

compiled during" an even-numbered year.

(3) The *General Information* section has also been amended to provide that only initial (first-time) submissions of the form shall be completed in their entirety. All other forms, including those due on November 30, 1981, will be preprinted by the Commission, containing the data that were previously-filed. The preprinted forms shall be changed, deleted or added to only as necessary to correct such previously-filed data.

(4) The *General Instructions* have been revised to provide that, when actual data are not available at the time of a filing, reasonable estimates of such data may be substituted.

(5) The words, "in and around the development" have been eliminated from *Code 20—Trails* of the Recreational Facility Definitions.

(6) *Code 66—Hunting Areas* has been revised to read, "Public or private areas open to the general public for the purpose of hunting."

(7) *Code 72—Motels, Hotels and Lodges* has been revised to read, "Overnight lodging establishments open to the general public for transient use that are within the development (or in the case of Part II, Item 41, that are adjacent to, or within the reasonable vicinity of, the development). This category includes, as one unit, each group of rental cabins that are generally rented or used on a daily basis. This category does not include *Code 70—Year-Round Homes, Code 71—Seasonal Cottages,* or *Code 80—Trailer Parks.*"

(8) Items 27 (a) and (b) in Part I of the *Specific Instructions* have been revised to require information about only the licensee's recreational costs and recreational revenues, respectively.

(9) Item 28 in Part I of the *Specific Instructions* has been amended to provide that the facilities reported in Items 28 and 29 include "privately-owned facilities."

(10) Item 30 is clarified to require the name of any cooperating agency or entity "assisting in the development of" the planned recreational facilities.

(11) The Note preceding Item 33 in Part II of the *Specific Instructions* has been amended to require that the facilities within the development are "land- and water-based facilities provided by licensees and others, including privately-owned facilities." The reference in the Note to licensee-provided facilities outside of the development has been corrected. Location of such facilities is now described as "adjacent to the development (project) boundary."

(12) Item 33 is revised as follows: The phrase "within or adjacent to the development (project) boundary" is eliminated. The following sentence has also been added: "DO NOT USE Codes 70, 71, 72, 73, 80 and 81."

(13) Item 41 in Part II of the *Specific Instructions* has been amended to provide that the recreational facilities for which reports are required in Items 41 and 42 include "privately-owned facilities."

The more important of the further changes to the regulations at § 8.11 are as follows:

(1) Clause (a)(1) has been amended to provide that copies of the form shall be submitted to Commission regional offices, pursuant to the requirements in the form.

(2) In clause (a)(2) the filing date for forms submitted subsequent to 1981 has been changed to April 1st of each odd-numbered year.

(3) Clauses (a)(3) and (4) have been changed to provide that only initial filings of the Form No. 80 must be completed in their entirety. All other filings due in 1981 and subsequently shall be completed only to the extent necessary to correct previously-filed data.

VI. Final Regulatory Flexibility Analysis

This final regulatory flexibility analysis is prepared pursuant to the Regulatory Flexibility Act (RFA),[19] which requires certain statements, descriptions, and analyses of final rules that will have "a significant economic impact on a substantial number of small entities". The broad purpose of the RFA is to ensure more careful and informed agency consideration of rules which may significantly affect small business and small government entities, and to encourage cost-benefit analyses of these rules as well as the agency's consideration of alternative approaches which may better resolve any unnecessarily costly or adverse effects on these small entities.

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[19] 5 U.S.C. 601–612.

The Commission prepared an initial regulatory flexibility analysis according to the requirements of section 603 of the RFA. That initial analysis was published as part of the Notice of Proposed Rulemaking in this docket.[11] In Parts I and II of the preamble of this final rule, the Commission has presented its reasons of its need for and its objectives of the rulemaking, in accordance with the requirements of section 604(a)(1) of the RFA. In sum, the final rule reduces substantially the reporting burden on *all* respondents (*i.e.*, both small and large entities) who file reports pursuant to § 8.11 of the Commission's regulations.

The final rule redesigns, simplifies, and updates the data in Form No. 80, the "Licensed Hydropower Development Recreation Report", reduces the number of data elements therein by approximately 60 percent and provides for preprinting of the forms. The changes reduce by about 75 percent the time required by each of the respondents to collect and record the necessary data; thus, instead of the approximately 40 hours formerly needed to complete each Form No. 80, it will now take only about 10 hours per form. This time savings should result in a significant economic savings to the respondents.

Section 604(a)(2) of the RFA requires a summary of the issues raised by the public comments in response to the initial regulatory flexibility analysis and the agency's response to those comments. The Commission is not including such a summary here because none of the comments received in response to the notice raised any issues with respect to the initial analysis.

Section 604(a)(3) of the RFA requires a description of each of the significant alternatives to the rule designed to minimize any adverse economic impact on small entities which were considered by the agency, and reasons for rejecting each alternative. From the viewpoint of regulatory flexibility, the significant alternatives to the rulemaking were to leave the existing provisions intact or to further reduce the reporting requirement.

The first alternative (leave the existing provisons intact) contradicts the objectives of the RFA. The primary purpose of this rulemaking is to reduce the reporting burdens from the current regulations. This can be accomplished by positive Commission action, such as that proposed in this docket.

With respect to the second alternative (further reduce the reporting requirements), this form has undergone extensive review over a period of five or six years. The data elements have been pared to an essential minimum in light of the intent of the Federal Power Act and the Commission's regulatory responsibilities specified in that Act. Therefore, the Commission cannot justify a further reduction in the data requirements for small entities and perform an adequate oversight of such licensees.

As a third alternative for this rulemaking, the Commission could have amended § 8.11(c) of the regulations. Paragraph (c) provides an exemption from the filing of Form No. 80 for licensees of projects having no recreational use. The Commission could have provided an exemption for licensees of projects wherein the recreational usage is below a predetermined amount (*e.g.*, less than 1000 visits per year). The Commission believes that this is not a reasonable alternative because it would contradict the statutory requirement in section 10(a) of the Federal Power Act which provides that each project licensed by the Commission "* * * will be best adapted to a comprehensive plan for improving and developing a waterway or waterways, for * * * beneficial public uses, including recreational purposes."

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[11] *See* Part III of the Notice of Proposed Rulemaking.

VII. Effective Date

The changes in this final rule will be effective on October 29, 1981, for reports to be filed on or before November 30, 1981 and for reports filed thereafter.

(Department of Energy Organization Act, 42 U.S.C. 7101–7352; E.O. 12009, 3 CFR 142; Federal Power Act, 16 U.S.C. 792–828c; Public Utility Regulatory Policies Act, 16 U.S.C. 2601–2635)

In consideration of the foregoing, the Commission amends Form No. 80 as set forth in Attachments A and B, and Parts 8 and 141 of Chapter I, Title 18, *Code of Federal Regulations*, as set forth below.

By direction of the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,296]

46 F. R. 50059 (October 9, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Pennsylvania—1); (Order No. 178)]

High-Cost Gas Produced From Tight Formations; Final Rule

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Pennsylvania Department of Environmental Resources, Bureau of Topographic and Geologic Survey, that the Medina Group be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective September 30, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or John Roy Johnson, (202) 357-8731.

Issued September 30, 1981.

SUPPLEMENTARY INFORMATION:

The Commission hereby amends § 271.703(d) of its regulations to include the Medina Group in Pennsylvania as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by the Director, OPPR, issued June 29, 1981 (46 FR 35119, July 7, 1981) [1] based on a recommendation by the Pennsylvania Department of Environmental Resources, Bureau of Topographic and Geologic Survey, (Pennsylvania) in accordance with § 271.703(c) that the Medina Group be designated as a tight formation.

Evidence submitted by Pennsylvania supports the assertion that the Medina Group meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Pennsylvania recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and, therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

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[1] Comments were invited and several comments supporting the recommendation were received. No party requested a public hearing and no hearing was held.

(Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. § 3301–3342; Administrative Procedure Act, 5 U.S.C. § 553.)

For the reasons stated herein, Part 271 of Subchapter H, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective September 30, 1981.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,297]

46 F. R. 50060 (October 9, 1981)

18 CFR Part 282

[Docket No. RM80-16; Order No. 177]

Incremental Pricing; Final Rule

Issued: September 24, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is amending its regulations on incremental pricing under Title II of the Natural Gas Policy Act (NGPA) to provide an exemption for natural gas used as a boiler fuel in the manufacture of fertilizer, agricultural chemicals, animal feed and food.

The final rule is subject to 30-day Congressional review before becoming effective.

EFFECTIVE DATE: Final rule becomes effective following 30 days of continuous session of Congress unless either House adopts a resolution of disapproval within that 30-day period.

FOR FURTHER INFORMATION CONTACT: Barbara Christin or Michael Kessler, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE, Washington, D.C. 20426, (202) 357-8033.

SUPPLEMENTARY INFORMATION: The Federal Energy Regulatory Commission (Commission) is amending its regulations on incremental pricing (18 C.F.R. Part 282) under Title II of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. §§ 3301–3432). Specifically, it is revising § 282.203 and adding new § 282.210 to exempt from incremental pricing natural gas used as boiler fuel in the manufacture of fertilizer, agricultural chemicals, animal feed and food, until such time as the Commission determines that there is an alternative fuel that is economically practicable and reasonably available.

This rule is issued pursuant to section 206(d) of the NGPA. Section 206(d) authorizes the Commission to exempt categories of users from the incremental pricing program established by Title II of the NGPA. Section 206(d)(1) authorizes the Commission "by rule or by order, [to] provide for exemption, *in whole or in part, of any other incrementally-priced industrial facility or category thereof.*" (Emphasis added.) Section 206(d)(2) provides that when the Commission promulgates an exemption by rule under section 206(d)(1), the exemption does not become effective until the day following a thirty-day Congressional review period unless either House of Congress adopts a resolution of disapproval.

I. Background

On August 14, 1981, the Commission issued a Notice of Proposed Rulemaking regarding the Treatment Under the Incremental Pricing Program of Natural Gas Used in the Manufacturing Process for Fertilize, Agricultural Chemicals, Animal Feed, or Food (Notice), 46 FR

41748 (August 17, 1981). The Notice fully describes the statutory framework and procedural history surrounding this rulemaking. In response to the Notice, the Commission received 35 comments, all of which have been considered before promulgation of this final rule.[1]

In considering the above-described exemption, the Commission recognized that agriculture was singled out for favored treatment in the NGPA. The agricultural use of natural gas was the only specific industrial use of gas expressly exempted from incremental pricing under Title II and given a preferred curtailment priority in Title IV. The "agricultural use" of natural gas was exempted from incremental pricing in section 206(b) of the NGPA. Section 206(b)(3) defines "agricultural use" as follows:

> (b)(3) Agricultural Use Defined.—For purposes of this subsection, the term "agricultural use," when used with respect to natural gas, means the use of natural gas to the extent such use is—
>
> (A) for agricultural production, natural fiber production, natural fiber processing, food processing, food quality maintenance, irrigation pumping, or crop drying; or
>
> (B) as a process fuel or feedstock in the production of fertilizer, agricultural chemicals, animal feed, or food.

This exemption is subject to the alternative fuel test defined in section 206(b)(2) of the NGPA. Section 206(b)(2) of the NGPA requires the Commission to promulgate a rule to exempt from incremental pricing only those agricultural uses of natural gas for which the Commission determines that an alternative fuel is not economically practicable or reasonably available.[2]

It is clear that by defining agricultural use as it did, Congress delineated a class of uses that merited special treatment under Title II of the NGPA. Included in this class of special uses are the fertilizer, agricultural chemicals, animal feed and food industries. Congress thus acknowledged the fundamental necessity of food and the vital role of energy to the food production process.

II. Discussion

A. Exemptions

Legislative intent. Although the exemption was proposed under the Commission's broad authority in section 206(d) of the NGPA, several commenters noted that, with regard to gas used in the production of fertilizer, agricultural chemicals, animal feed and food, section 206(b)(3)(B) of the NGPA limits the availability of the "agricultural use" exemption to process or feedstock uses. These commenters asserted that, by providing an agricultural exemption from incremental pricing for the process and feedstock use of natural gas by the industries enumerated in section 206(b)(3)(B), Congress thereby expressed its intent that the boiler fuel use of gas by these same industries should be afforded the same pricing treatment as all other industrial boiler fuel users of gas.

To further support this argument, these commenters explored the legislative history of the NGPA. By examining statements made by various interest groups before House and Senate subcommittees during deliberation of the Act, these commenters argued that various industrial groups contemplated that only process and feedstock uses of natural gas would be exempt from incremental pricing surcharges and, conversely, that boiler fuel should not be exempt.[3]

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[1] Atlanta Gas Light Company (Atlanta Gas) filed comments in the instant docket seeking clarification of the billing treatment to be afforded certain fertilizer manufacturers it serves. These comments urge the Commission to determine how Atlanta Gas should handle past billing periods for which incremental pricing surcharges were assessed but were not paid by the customers on the basis of a claimed exemption for use in fertilizer production. The Commission intends to act expeditiously to resolve this issue, which is of concern not only to Atlanta Gas, but also to other distribution companies. Such action will be undertaken in the context of Docket No. RM80-75. Atlanta Gas' comments will be deemed to have been filed in that docket as well as in the instant docket.

[2] It should be noted that the Commission has not yet promulgated the rule required for section 206(b)(2). Only then will the scope of the "agricultural use" exemption be finally determined. *See* pp. 15-18, *infra.*

In this connection, the Commission notes that the legislative history of the NGPA is far less than crystal clear on this point. However, there is legislative history that militates against the above-stated position. Pertinent history is a colloquy between Senator Talmadge, then Chairman of the Senate Committee on Agriculture, Nutrition and Forestry, and Senator Jackson, then Chairman of the Senate Committee on Energy and Natural Resources, during debate on the conference report on the NGPA. Colloquies such as this are frequently used to announce Congressional intent with respect to legislation.

Relevant portions of the colloquy are as follows:

> Mr. Talmadge: . . . [S]ection 206(b) assures agriculture the same high priority accorded households and small businesses in protection against sharply high natural gas prices by exempting agricultural users from the incremental pricing features of the bill . . .
>
> Mr. Jackson: The Senator is correct. . . .
>
> Mr. Talmadge: . . . Concerning the agricultural exemption for incremental price increases, does this mean that farmers, processors, food warehousemen, and *fertilizer, and other agricultural chemical manufacturers* will not experience the higher price increases that will bring in new supplies of natural gas? . . .
>
> Mr. Jackson: . . . [T]hose increases will not be as great as boiler fuel or other industrial price increases.
>
> There is no guarantee to anyone that there will not be price increases, *but agriculture will be accorded that benefit which basically runs to the residential and small business user.* (Emphasis added.)

Discretely, this language supports three propositions. First, agriculture is to be accorded the same kind of benefits as residential and small commercial users under the incremental pricing program. Second, manufacturers of these products are to be protected from higher prices of natural gas regardless of its use as a boiler fuel because boiler fuel is disfavored in connection with industrial, but not agricultural, uses. Last, the boiler fuel use of natural gas in the fertilizer, agricultural chemical, animal feed and food industries should not be distinguished from other agricultural boiler fuel uses. More importantly, reading the colloquy as a whole casts significant doubt on the assumption that boiler fuel applications of gas connected with fertilizer, agricultural chemicals, animal feed and food industries were *ipso facto* relegated to a lower status than other agricultural uses. The Commission emphasizes that, although the definitions of agricultural use in Titles II and IV are substantially similar, this conclusion is applicable only to considerations under Title II. Congress had, and apparently adopted, sound policies to protect certain agricultural boiler fuel uses from incremental pricing, but the Commission agrees with the Court of Appeals in *Process Gas Consumers Group* v. *United States Department of Agriculture*, No. 80-1558 (D.C. Cir., June 30, 1981), slip op. at 13-14, that those reasons do not extend to Title IV for the policy reasons that underlay the Federal Power Commission's determination that boiler fuel was in *all* cases a low-priority use. In short, there is a difference between advantages in access to fuel and advantages as to the price that is paid for it.

Other commenters argued that, by promulgating the instant exemption pursuant to the Commission's broad authority under section 206(d) of the NGPA, the Commission is not limited by the language of section 206(b)(3)(B). These commenters noted that the Commission has broad discretion to issue exemptions in addition to those specifically enumerated in sections 206(a)-(c) of the NGPA. The commenters cited *Ohio Association of Community*

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[3] *See e.g.* Hearings on H.R. 6831, *et al.* Before the Subcommittee on Energy and Power of the House Committee on Interstate and Foreign Commerce, 95th Cong., 1st Sess. 992-93 (May 17, 1977); Hearings Before the Senate Committee on Energy and Natural Resources on S. 256 and S. 1469 (Pt. D), 95th Cong., 1st Sess. 524 (June 14, 1977).

Action Agencies v. *Federal Energy Regulatory Commission (Ohio Association)*, No. 80–1208 (D.C. Cir., June 15, 1981), as support for this proposition. In *Ohio Association,* the Court reviewed the propriety of the Commission's actions in Order No. 51, which exempted all industrial boiler fuel facilities from incremental pricing surcharges exceeding the level of high sulfur No. 6 fuel oil.[4] The Commission issued Order No. 51 pursuant to its authority under section 206(d) notwithstanding the fact that section 204(e) provides specific statutory guidelines for the Commission's issuance of a rule or order reducing the alternative fuel cost ceiling below the level of No. 2 fuel oil.[5]

The Court of Appeals rejected the challenge to the Commission's use of section 206(d) to exempt industrial users from incremental pricing surcharges above the price of high sulfur No. 6 fuel oil. The Court found that the broad language of section 206(d) was intended by Congress to give the Commission the discretion to modify implementation of the incremental pricing program in view of the innovative nature of the program. The Court stated at slip op. 19–20 that:

> In the context of the entire Act, a broad exemption power is entirely consistent with the objectives and concerns expressed by Congress during the passage of Title II. Moreover, the portions of the legislative history which specifically refer to section 206(d) indicate an express intent to maximize the Commission's discretion in administering the innovative incremental pricing system.

Thus, these commenters argued, the Commission is not limited in promulgating a rule under section 206(d) by the definitional limitations in section 206(b)(3)(B).

In support of the Commission's issuance of this exemption under section 206(d), many commenters also noted the vital relationship of fertilizer, agricultural chemicals, animal feed and food to agricultural production. Representing fertilizer manufacturers, one commenter submitted that over one-third of domestic food and fiber production is directly attributable to the application of fertilizer. Moreover, the nutrients supplied by fertilizer must be replenished each year, and farmers must make substantial fertilizer purchases on a continuing basis. Representing animal feed and food producers, two commenters indicated that, like the other agricultural products specified in section 206(b)(3)(B), pet food production is related to the production of food for human consumption:

> The pet food industry provides a critical source of income to the processors of livestock, poultry, and seafood for human consumption. By providing a market for more than one-third of the by-products of these industries, the production of pet food serves to create a demand for farm products—most of which cannot be used for human consumption—and thereby reduces the cost of human food for consumers. [Comments of Kal Kan Foods, Inc.]

Thus, by issuing the rule in this docket, these commenters argued that the Commission is addressing a distinct class of users of natural gas who have a vital link to agricultural production.

In opposition to the proposed rule, several commenters argued that, once the Commission starts granting certain boiler fuel end-use exemptions from incremental pricing under section 206(d), there is no basis upon which to exclude other boiler fuel uses from incremental pricing exemptions. In addition to this argument, these commenters, citing *Process Gas Consumers Group* v. *United States Dept. of Agriculture*, No. 80–1558 (D.C. Cir., June 30, 1981) slip opinion at 13–14, also argued that, as a policy matter, section 206(d) exemptions should not be extended solely on the basis of the ultimate product.

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[4] Rule Exempting Industrial Boiler Fuel Facilities From Incremental Pricing Above the Price of No. 6 Fuel Oil, Docket No. RM79–21, issued September 26, 1979 (44 Fed. Reg. 57778 (October 5, 1979)).

[5] The Court cited the numerous concerns expressed by various leaders in Congress with the concept of incremental pricing to substantiate its interpretation of the role Congress intended section 206(d) to play in implementing the new pricing approach. *See, Ohio Association,* slip opinion at 20–24.

On the other hand, several commenters argued that the Commission could reasonably deny exemptions to other industries for two reasons. First, the commenters noted that Congress recognized the importance of the fertilizer, agricultural chemical, animal feed and food industries in section 206(b)(3)(B). By using its section 206(d) authority to exempt the boiler fuel use of gas to manufacture these products, the Commission is furthering the Congressional intent to give these industries a preferred status under the NGPA. Second, several commenters argued that the subject industries provide primary inputs to agricultural production and, therefore, deserve a preferred exemption status vis-a-vis more remote agriculturally-related industries.[6]

One commenter noted that it was Congress that recognized the link, whether direct or indirect, between certain end products and agriculture. Thus, Commission issuance of the instant exemption would further the Congressional intent that these end products receive preferred treatment under the NGPA.

Price Impact. Other questions asked by the Commission in the Notice relate to arguments set forth by commenters in response to the notice issued on February 21.[7] Many commenters argued that the imposition of incremental pricing surcharges on natural gas used as boiler fuel in fertilizer, agricultural chemicals, and animal feed and food production would have an immediate and detrimental impact on the agricultural sector. It was asserted that incremental pricing surcharges inevitably would increase the cost of fertilizers and other agricultural inputs, and these increased costs either would be passed on through the chain of production beginning with the farmer or, to the extent these costs are absorbed by the farmer, would reduce farm income which is being squeezed by high costs and lower crop prices.

It was further argued that the impact upon the agricultural sector would be particularly acute at this time, because rising agricultural input costs, depressed commodity prices, heavy crop and livestock losses, and extremely high costs of operating capital have combined to yield a net farm income which, in real value, is the lowest since the days of the Great Depression. The commenters concluded that the agricultural sector should not now be burdened with additional, unnecessary costs which would further depress farm income and productivity and which would increase inflationary pressures.

In addition, the fertilizer manufacturers claimed that the imposition of incremental pricing surcharges would intensify the competitive disadvantages of many American fertilizer manufacturers with respect to fertilizer imports. For example, it was argued that foreign nitrogen fertilizer manufacturers are already undercutting domestic prices and driving some domestic manufacturers out of business. Price increases resulting from incremental pricing surcharges would accelerate this growing dependence upon foreign sources for key agricultural inputs.

In the Notice, the Commission requested additional information of a more specific nature so that it could properly evaluate the above-described arguments set forth by commenters in support of an incremental pricing exemption.

Many commenters who responded to the Commission's questions agreed that the farmer or the consumer will eventually bear production cost increases, but were unable to precisely quantify the impact of incremental pricing surcharges on consumer prices and net farm income. Instead, the commenters focused on the effect that incremental pricing surcharges would have on their production costs.

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[6] The Commission wishes to emphasize that it does not question the importance of other industries to the American economy, nor does it suggest that an exemption from incremental pricing could not be granted to other industries on the basis of some other relevant policy consideration.

[7] Notice of Opportunity to Comment on Whether a Rulemaking Proceeding Should Be Established, Docket No. RM80-18, issued Feb. 21, 1980 (45 FR 13122 (Feb. 28, 1980)).

For example, National Soybean Processors Association stated that one producer of animal feed estimated that even a ten percent increase in gas costs resulting from incremental pricing would increase feed manufacturing costs by two percent. InterNorth, assuming a differential of one dollar per Mcf between the average industrial gas price and the No. 6 ceiling price, projected that the annual increases in affected customer costs would be four million dollars due to incremental pricing surcharges.

The Department of Agriculture stated that, while savings to a given producer from an exemption may be substantial, the savings to the industries as a whole are minimal. The total cost of the interstate gas used as boiler fuel by the industries in question based on 1977 estimates represents less than 0.3 percent of the entire production expenditures of these industries. Incremental pricing would increase the cost of production of all agricultural chemicals and fertilizer between 0.02 percent and 0.05 percent and would raise the cost of crop production between 0.001 percent and 0.004 percent. The Department of Agriculture also stated that these projected cost increases in crop production are insubstantial and that net farm income would decline only slightly if the fertilizer, agricultural chemical, animal feed and food industries were subject to incremental pricing.

Some commenters argued that consumers would be "irreparably harmed" if the Commission does not grant an incremental pricing exemption to manufacturers of fertilizer, agricultural chemicals, animal feed and food. They stated that consumers would ultimately bear all of the cost increases in the form of higher prices for food products.

The Department of Agriculture, however, noted that incremental pricing of the gas used to manufacture these products is not likely to produce much effect on consumer food bills. Assuming the worst (fifteen percent increase per year in natural gas prices by 1984), the Department concluded that consumer expenditures for food would rise only eight cents per year per person.

Conclusion. The arguments in favor of granting the exemption, as well as the arguments against the exemption, are both very compelling and the question of exemption is close. Nevertheless, the Commission has determined to grant the exemption for two reasons. First, the arguments in favor of granting the exemption outweigh the counter-arguments, if only slightly. On balance, the Commission believes the comments demonstrate that agricultural production will be furthered by granting an exemption. Second, granting the exemption appears to be consistent with Congressional intent to single out generally this industry for preferred treatment in connection with incremental pricing. Therefore, for the reasons stated above and in the comments supporting the exemption, the Commission believes it to be in in the public interest to issue this final rule granting exemption pursuant to section 206(d) of the NGPA on a prospective basis only.

The Commission is concerned that, at least with reference to incremental pricing, Congress may have intended to include the subject boiler fuel uses within the agricultural exemption.

Although sound policy connected with agricultural production, previously expressed by Congress in the debate and drafting of the NGPA, supports the exemption, the Commission recognizes that Congress will have an opportunity to reach an opposite result.

B. Alternative Fuel Test

As noted above, section 206(b)(2) requires the Commission to promulgate an alternative fuel test for "agricultural uses." In the Notice, the Commission requested comments on whether a section 206(d) exemption for facilities which manufacture fertilizer, agricultural chemicals, animal feed and food should be made specifically subject to an alternative fuel test such as the one set forth in section 206(b)(2) of the NGPA for "agricultural uses."

The comments received have convinced the Commission to make this final rule subject to the alternative fuel test to be promulgated under section 206(b)(2). To do otherwise would be inequitable, because it would effectively give the instant uses of natural gas a more favored status with respect to incremental pricing than the agricultural uses to which they are vitally connected. Therefore, when the Commission develops an alternative fuel test for agricultural uses of natural gas pursuant to § 282.203(a)(2) of its rules, the boiler fuel use of natural gas in the production of fertilizer, agricultural chemicals, animal feed and food will be subject to that alternative fuel test because of its link to agricultural production.

C. "Integral" Use

In the Notice, the Commission also sought comment on the appropriate method for determining whether a particular use of steam is "integral" to the manufacturing process of fertilizer, agricultural chemicals, animal feed and food. Several commenters suggested that the "integral use" test be deleted in its entirety. The Commission has decided to delete the restriction in the proposed rule that the steam be used as an integral part of the manufacturing process. The Commission believes that the "integral use" requirement is subsumed within the requirement that the natural gas be used in the manufacture of the subject products. Therefore, in the final rule all natural gas used as a boiler fuel in the manufacture of fertilizer, agricultural chemicals, animal feed and food is eligible for an exemption from incremental pricing surcharges.

One commenter suggested that the Commission use Standard Industrial Classification (SIC) Codes to designate the users who would be eligible for an exemption. The Commission has adopted this system, because the use of SIC Codes is consistent with the Commission's use of SIC Codes for other end-use exemptions. (*See* § 282.202(a).)

III. Congressional Review and Effective Date

As already noted, the rule set forth below is issued pursuant to section 206(d) of the NGPA. That section requires that the rule be submitted to the Congress for review prior to taking effect. After submission to each House of Congress, the rule may take effect on the day following 30 days of continuous session of Congress (as set forth in subsection 507(b) of the NGPA) unless either House adopts a resolution of disapproval within that 30-day period. Accordingly, this rule will be effective, on a prospective basis only, on the day following expiration of the 30-day period for Congressional review.[8]

In consideration of the foregoing, if neither House of Congress passes a Resolution of Disapproval of the regulations transmitted to it in this rulemaking within 30 days of Congressional review, as determined in accordance with section 507(b) of the NGPA, Part 282 of Subchapter I, Chapter 1, Title 18, Code of Federal Regulations, is amended as set forth below, effective on the day following expiration of the 30-day Congressional review period.

(Natural Gas Policy Act of 1978, Pub. L. No. 95–621, 92 Stat. 3350, 15 U.S.C. §§ 3301–3434).

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[8] The Commission notes that the exemption provided by this rule has no retroactive effect.

By the Commission. Commissioner Sheldon concurred with a separate statement attached.

Kenneth F. Plumb,
Secretary.

Sheldon, Commissioner, *concurring.*

I agree with my colleagues' position that agricultural use of natural gas was given a preferred status under the Natural Gas Policy Act (NGPA). Whether or not this preferred treatment extends to the boiler fuel use of natural gas for manufacturing agricultural related products is very much at issue and has generated a substantial amount of controversy.

Obviously, Titles II and IV of the NGPA were intended to have different meanings. The comments we have received attest to this fact. But the precise meaning needed to resolve this issue, has been clouded by the conflicting "legislative history"[1] and can be resolved only by its authors. Therefore, I *concur* in referring this rule to the Congress.

My separate statement should not be viewed as opposition to the agricultural industry. As my colleagues are well aware, the rule itself raises additional concerns which need to be addressed. The incremental pricing exemption authorized by this rule is subject to the "alternate fuel test", a statutory requirement in Section 206(b) which the Commision has not promulgated, regardless of the fact, the NGPA (Section 206(b)) mandated it to be in effect eighteen months after the date of enactment of the NGPA.

I would expect the Commission to act as expeditiously on the statutorily required rule as on the present exemption. Since the Commission has not specified when it will act, in my view, it would be appropriate that our rule on the "alternate fuel test" be concluded by November 15, 1981.

Georgiana H. Sheldon,
Commissioner.

[¶ 30,298]

46 F. R. 50511 (October 14, 1981)

18 CFR Part 34 and 131

[Docket No. RM 81-18; Order No. 182]

Application for Authorization of the Issuance of Securities or the Assumption of Liabilities

October 7, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is revising Part 34 of its regulations, "Application for Authorization of the Issuance of Securities or the Assumption of Liabilities." The Part 34 provisions are clarified and simplified and certain of the requirements therein are reduced or deleted.

The changes are part of the Commission's ongoing effort to update its reporting and filing requirements and to eliminate unnecessary reporting burdens for those entities which file applications or reports with the Commission pursuant to Part 34.

DATE: The revisions are effective October 7, 1981.

FOR FURTHER INFORMATION CONTACT: Robert E. Hildebrand, Office of Chief Accountant, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Room 3408N, Washington, D.C. 20426 (202) 357-9184.

SUPPLEMENTARY INFORMATION: The Federal Energy Regulatory Commission (Commission) is revising its regulations at 18 CFR Part 34, "Application for Authorization of the Issuance of Securities or the Assumption of Liabilities." These revisions clarify and simplify the Part 34 provisions and delete or reduce certain of the requirements therein. The revisions are made as part of the Commission's effort to reevaluate all of its data requirements and to eliminate the reporting of data that are not necessary for Commission regulatory purposes.

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[1] Final Rule at page 5 fn. 3 and page 6.

Part 34 provides filing requirements for any issuance of a security or assumption of liability by a public utility, licensee or other entity for which approval must be obtained from the Commission under sections 19, 20 and 204 of the Federal Power Act (FPA) (16 U.S.C. 812, 813, 824c).

This final rule to amend Part 34 was preceded by a Notice of Proposed Rulemaking issued February 27, 1981 (46 FR 15513, March 6, 1981). Among the proposed changes to Part 34 were consolidation and simplification of the requirements for competitive bidding and negotiated placements, deletion of certain of the data elements which were previously required in an application, and addition of requirements to report certain items which were previously obtained through individual data requests.[1]

I. Summary and Analysis of Comments

A. General

In response to the Notice of Proposed Rulemaking, the Commission received six comments.[2] Two of the commenters, Idaho and Pacific, generally approved the proposed changes to Part 34 and commended the Commission for clarifying and abbreviating the requirements for security applications. Two other commenters, SCE&G and Iowa Electric, expressed certain concerns about the Commission's procedures for approving security issuances. The remaining commenters, Edison and Keleher offered alternative language for § 34.1 of the regulations.

Pacific stated that the revisions should increase the efficiency of the process and reduce costs associated with securities applications by about 25 percent. SCE&G said that it uses about 100 man hours and $5,000 to prepare an application under the current requirements; and that these figures could be reduced by more than 90 percent if the Commission approved this company's suggestions to further reduce the reporting requirements in the application. Iowa Electric stated that its reporting burden associated with the Part 34 requirements would not materially change as a result of this rulemaking.

SCE&G stated that the Commission's proposed requirements: (1) Do not reflect the "real world with regard to issuance of commercial paper," (2) continue to impose unnecessary requirements with respect to short-term borrowing, (3) do not go far enough in applying a short-form application for borrowing up to 5 percent of par value of outstanding securities, and (4) should permit a short-form application for borrowing up to 15 percent of par value of a utility's outstanding securities. SCE&G stated that the requirement of a long form application for short-term debt involving more than 5 percent of par value was "unrealistic" and was "unduly burdensome without any corresponding public benefit." According to SCE&G, much of the essential information in the long-form application, including all of Exhibits H, I and J could be derived from data included in or attached to Form No. 1 reports filed with the Commission.[3]

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[1] For a detailed discussion of the particular changes proposed for Part 34, see pp. 2–6 of the Notice of Proposed Rulemaking in this docket.

[2] Idaho Power Company (Idaho); Iowa Electric Light and Power Company (Iowa Electric); Pacific Power and Light Company (Pacific); Southern California Edison Company (Edison); South Carolina Electric and Gas Company (SCE&G); and Keleher and McLeod, P.A. (Keleher).

[3] Form No. 1 is the "Annual Report for Electric Utilities, Licensees and Others (Class A and Class B)" and is required to be filed by § 141.1 of the Commission's regulations.

With respect to raising the limitation of outstanding debt from 5 percent to 15 percent, the Commission notes that section 204(e) of the Federal Power Act specifically prescribes the 5 percent of par value limitation. Therefore, revision of the 5 percent limitation would require an Act of Congress rather than Commission action.

The Commission, however, has further simplified the "long-form" requirements for utilities which apply for short-term issuances of securities. Both Exhibits I (§ 34.4(i)) (information concerning the construction program) and J (§ 34.4(j)) (estimates of peak load and capacity) have been deleted from Part 34 because the Commission may obtain these data from information filed in, or attached to, the Form No. 1.[4] Data in Exhibit J are also available to the Commission through ERA Form No. 119–A, "Annual Projected Electric Utility Energy and Capacity Report." Therefore, a separate filing of Exhibit J with the Commission is no longer necessary.

The Commission notes that applicants who file for any short-term issuances of securities are not required to comply with the following provisions in Part 34 because such provisions relate only to long-term offerings: (1) Section 34.3(e)(1), "Type and nature of securities"; (2) § 34.3(e)(3), "Interest or dividend rate, if any"; (3) § 34.3(e)(4), "Dates of issuance and maturity"; (4) § 34.3(e)(5), "Institutional rating of the securities, or if the securities are not rated, an explanation thereof"; (5) § 34.3(e)(6), "Any stock exchange on which the securities will be listed"; (6) § 34.3(e)(7), "Information in support of an exemption from competitive bidding requirements pursuant to § 34.2(a)(1) (i), (ii) or (iii)"; (7) Exhibit F (§ 34.4(f)) (The SEC Registration Statement); (8) Exhibit G (§ 34.4(g)) (Copies of public invitations for proposals to purchase or underwrite securities offered for issuance); or (7) Exhibit H (§ 34.4(h)) (Summaries of data from proposals for negotiated placements).

SCE&G also argued that the attorney's opinion on legality of the debt could be omitted from the application if the signature of the attorney on the application were interpreted as a certification of legality.

The Commission notes that the attorney's opinion on legality of the debt had been proposed for deletion in the notice and is hereby eliminated from the Part 34 requirements.

Iowa Electric objected to the Commission's entire process for authorizing the issuance of securities. The proposed rule in this docket would not materially change the reporting burden of the application process, according to Iowa Electric, and does nothing to address the basic issues raised at the Electric Power Informal Public Conference held at the Commission on March 6, 1981.[5] Specifically, Iowa Electric claimed that competitive bidding procedures for the sale of securities "is completely untenable in today's market" and that the Commission's negotiated bidding process is, in fact, competitive bidding.

The Commission notes that the March 6, 1981, Informal Conference dealt with broad issues more directly related to rate matters than security issuances. However, with respect to Iowa Electric's specific concerns about the competitive and negotiated bidding processes, the Commission believes that these processes are proven methods of authorizing the sale of securities and are, therefore, "compatible with the

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[4] Pacific suggested that Exhibit I should be clarified to provide the timing or cost changes which trigger revisions to information reported in the exhibit. Because the exhibit is eliminated by this final rule, this clarification is no longer necessary.

[5] (Docket No. EL81–7–000) The purpose of the hearing in this docket was to obtain views and comments from interested persons concerning the financial health of electric utilities and to determine ways in which the Commission could improve the situation consistent with its responsibilities to electric utility consumers. Copies of documents in this proceeding are on file in the Commission's Division of Public Information, Room 1000, 825 North Capitol Street NE., Washington, D.C. 20426.

"public interest," according to section 204(a) of the FPA. Furthermore, competitive bidding remains the required method for security issuances subject to regulation by the Securities and Exchange Commission pursuant to the Public Utility Holding Company Act of 1935 (15 U.S.C. 79–79z–6).[6] The negotiated bidding process is not synonymous with the competitive bidding process. Competitive bidding is accomplished through public invitation for bids. Negotiated placements are exempted from this public invitation process. The only elements common to the competitive bid process and the negotiated placement process are the prohibitions respecting competitive bids and negotiated placements in § 34.2(e), and the written application requirements specified in § 34.3.

Iowa Electric also stated that the Commission should seriously consider adopting a process wherein approval of security issuances would be limited to the appropriateness of a pro forma capital structure. Iowa Electric added that once a pro forma capital structure was reviewed and approved by the Commission, the company would be permitted to have access to the market at times and on terms deemed to be in its best interests.

Pursuant to section 204(a) of the FPA, "no public utility shall issue any security, or assume any obligation or liability as guarantor, indorser, surety or otherwise in respect of any security of another person, unless and until, and then only to the extent that, upon application by the public utility, the Commission by order authorizes such issue or assumption of liability." The Commission does not believe that the approval of a utility's pro forma capital structure would constitute the authorization of issuances of securities or assumption of liability that is prescribed in section 204(a). Furthermore, capital structures are subject to changeable market conditions and are necessarily an internal consideration for each company. Therefore, it would not be in the public interest for the Commission to review and approve capital structures.

Iowa Electric also stated that revisions to Part 34 should be deferred until the basic problems with the security authorization process were addressed. The Commission will not defer this final rule to revise its security application procedures because the method used for the authorization of securities, is, in the Commission's opinion, a workable method. Furthermore, in response to comments received in this docket, the Commission has, where possible, made further reductions in its application requirements to ease the utilities' reporting burden. The Commission must continue to require certain basic data in order to make a reasonable determination that a proposed issuance or assumption "is for some lawful object within the corporate purposes of the applicant and compatible with the public interest * * *" (section 204(a), FPA).

B. Discussion of Particular Sections

1. *Section 34.1.* Among its specific comments, Pacific opposed the deletion of the small issue exemption from competitive bidding for securities of less than $1 million.[7] Pacific said that a small issue exemption should be retained and increased to $5 million to facilitate financing at this modest level.

A small issue exemption of 5 million dollars or even 10 million dollars is of no benefit to most companies because of the prohibitively high costs associated with the issuance of stocks or bonds for these relatively small amounts. The Commission, therefore, has eliminated a meaningless regulation to reflect the realities of the financial world. The Commission also notes that a company may apply for exemption from the competitive bidding requirements according to the provisions of § 34.2(a)(1)(iv) of the Commission's regulations. The company could, therefore, obtain a "small issue exemption" for a particular security issuance if the Commission finds that the noncompetitive placement is consistent with the public interest.

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[6] Iowa Electric suggested eliminating clause (5) of § 34.3(c) and modifying certain items in Exhibit H (§ 34.4(h)). These suggestions are discussed in connection with Pacific's comments concerning those issues at subsections 2 and 3 of this Part.

[7] The small issue exemption was provided at § 34.1a(a)(3) of the previous regulations.

Both Edison and Keleher offered suggestions to revise § 34.1(c)(1). This provision exempts from the Commission's review security issuances by a utility, if the State in which the utility is organized and operates regulates the issuance of such securities. The proviso in the § 34.1(c)(1) exemption states "that such utility must obtain express authorization for such State agency prior to the issuance of such securities." Edison, an electric utility which is organized and operates in California, stated that California statutes do not provide explicit statutory power for the California Public Utilities Commission (CPUC) to "authorize" certain of Edison's transactions. Under CPUC's broad regulatory powers, however, Edison has sought and received "approvals" of these transactions. Edison stated that § 34.1(c)(1) should provide for authorization "or approval" from such State agency. This change would assure that a company would not have to proceed before both the State commission and the Federal Energy Regulatory Commission for "authorization" prior to issuance of securities.

Similarly, Keleher inquired whether the "approval" for security issuances under the New Mexico Public Service Commission regulations may be construed to be "express authorization" according to § 34.1(c)(1).

The Commission has added the word "approval" to the proviso, as requested. In addition, the Commission has substituted the word "written" for the word "express" so that the proviso now states that, "* * * such utility must obtain written authorization or approval" from the appropriate State agency prior to the issuance of the particular securities. The change was made to clarify that the authorization (or approval) obtained from a State agency for a security issuance or obligation must be evidenced by a written order. However, so long as the State agency has the power to ratify an issuance and does so in writing, any appropriate language of endorsement may be used.

Pacific requested that the exemption from Commission security issuance rules under § 34.1(c)(3) for certain qualifying facilities be extended to include an exemption for alternative energy resource financing by and for regulated utilities. This exemption, according to Pacific would "further promote utility ventures into such resources."

The Commission will not exempt from the requirements in Part 34 energy resource financing by and for regulated utilities. Each of the exemptions in § 34.1(c) is authorized by statute. An exemption for energy resource financing is not so authorized and, therefore, is not subject to exemption from the Commission's securities regulations.[4]

2. *Section 34.3.* Iowa Electric was opposed to the requirement in § 34.3(e)(5) (institutional rating of securities) because the information prescribed in that clause would not yet be available when an application was filed.

The Commission believes that Iowa Electric could comply with § 34.3(e)(5) because it requires an "institutional rating of the securities—or *if the securities are not rated*, an explanation as to why they are not rated * * *" (Italics added.) Thus, an explanation would be required in situations where the securities are not rated, either as a matter of course or because the rating process has not been completed as of the date of the filing. The Commission has also amended this provision to require as part of the explanation an estimate of what the rating will be, once the rating process is completed. Thus, the best available information about the institutional rating would be provided, without a burden to the applicant.

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[4] The exemption for a utility orgainzed and operating in a State which regulates securities prior to their issuance, and the exemption for short-term notes or drafts, are provided for in section 204 of the Federal Power Act. The exemption for certain qualifying facilities is provided for in section 210 of the Public Utility Regulatory Policies Act of 1980 (16 U.S.C. 2601–2635).

Pacific stated that the requirements in § 34.3(e) (5) and (6),[9] while not burdensome, are possibly duplicative of information filed in the Securities and Exchange Commission (SEC) Registration Statement. Pacific also stated that in the case of publicly-offered securities, the data required in § 34.3(k) and (1) (limitations on interest and dividend coverage, and rate change summary, respectively) are reported in the SEC Registration Statement. Pacific urged the Commission to provide for incorporation by reference of such data in the securities application.

The Commission agrees with Pacific's suggestions and notes that a copy of the SEC Statement is filed with the Commission pursuant to § 34.4(f), Exhibit F. Therefore, the Commission has provided in § 34.3 that, in lieu of filing the information required in paragraphs (e), (k) and (1), a specific reference may be made to the portion of the SEC Registration Statement which includes the information required in these paragraphs.

3. *Section 34.4.* Pacific proposed the deletion of four items required in Exhibit H (§ 34.4(h)).[10] These were items (viii), "Offering price to the public or to other purchasers"; (ix), "Discount or premium"; (xi), "Net proceeds to company for each unit of security and for the total issue"; and (xii), "Net cost to the company for securities with a stated interest or dividend rate". Pacific argued that this information could be discussed in item (xiii), "Other pertinent data," and in staff information requests according to the current procedure. Iowa Electric criticized the same items (viii), (ix), (xi) and (xii), and also item (iii), "Total dollar amount of issue." Iowa Electric stated that these data are not available to underwriters until immediately before the public offering of securities and, therefore, cannot be reported in the securities application.

The Commission has retained items (viii), (ix), (xi) and (xii) of Exhibit H because each of these requirements describes the criteria which are most frequently used in the selection of a bid. They are listed as individual items so that the Commission may determine the extent to which companies rely on these data in selecting and justifying negotiated financing. This categorization is meant to assist the Commission in utilizing and analyzing the data reported in Exhibit H; it should not discourage applicants from using and describing other criteria for selecting a bid. Item (xiii) was specifically included as a summary item in Exhibit H for the reporting of any other information that the company wished to include.

In response to Iowa Electric, the Commission has amended § 34.4(h)(1) to provide that the summaries of proposals for negotiated placement of securities may include estimated information, if actual data are not available. These data must, however, be identified as estimates.

4. *Section 34.10.* Pacific stated that the "Report of Securities Issued" (18 CFR § 132.43) which is required to be filed under § 34.10 could not be timely filed with all costs final in the proposed 45-day period because some expenses and fees are not determined or billed within 45 days after completion of a security sale. Pacific suggested that the requirement be amended to provide for

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[9] Section 34.3(e)(6) requires stock exchange identification data.

[10] Exhibit H prescribes summaries of data from each proposal received by the applicant for a negotiated placement of securities offered for issuance.

"as available" reporting within 45 days and final reporting by 180 days.

The Commission has amended § 34.10 to provide that the report shall be due no later than 180 days after the sale or placement of equity or long-term debt or entry into another contractural obligation authorized in Part 34.

II. Summary of Changes to the Part 34 Requirements

The Commission has adopted the changes to Part 34 of its regulations which were proposed in the Notice of Proposed Rulemaking. In addition, further revisions are made in this final rule as a result of the comments received in this docket. They are summarized as follows:

(1) Section 34.1(c)(1) is amended in the proviso to state that a utility must obtain "written authorization or approval" from the appropriate State agency prior to the issuance of particular securities.

(2) Section 34.3 is amended to provide that, in lieu of filing the information required in paragraphs (e), (k) and (l), a specific reference may be made to that portion of the SEC Registration Statement which includes the necessary data.

(3) Section 34.3(e)(5) is amended to require an institutional rating of securities—or if the securities are not rated, an explanation as to why they are not rated and if such securities will be rated, an estimate of such rating.

(4) Exhibit H (§ 34.4(h)) is amended in paragraph (1) to provide that the required information may be estimated if actual data are not available, provided such data are identified as estimates.

(5) Exhibits I and J (§ 34.4(i), (j)) are deleted because the information required therein is available in Form No. 1 reports and information in Exhibit J may also be derived from ERA Form No. 119–A.

(6) Section 34.10 has been revised to require that the "Report of Securities Issued" (§ 131.43) shall be filed within 180 days after the issuance of securities.

In addition to clerical and conforming changes, the Commission has made the following additional revisions to the regulations at Part 34:

(1) A definition for the word "State" has been added at § 34.1(b)(4), based upon the definition of "State" in section 3(6) of the Federal Power Act.

(2) Section 34.2(b)2)(i)(B) is amended. That provision requires that upon receipt of an exemption from competitive bidding requirements, a utility "shall negotiate with, and obtain proposals with regard to placement of such securities from, at least three prospective dealers, purchasers or underwriters." The Commission has added "unless otherwise authorized by the Commission" after the word "underwriters." The Commission has determined that in certain instances (*e.g.*, those involving unsolicited proposals or "Eurodollar" financing), deviations from the standard of "three prospective dealers purchasers or underwriters" may be appropriate.

(3) Section 34.3(m) is modified to eliminate from the Federal Register requirements, Item (3), "the purpose of the issuance," because this information is not required in a Federal Register notice.

(4) Section 34.4(d) (Exhibit D) is modified to eliminate the requirements for "supporting plant schedules" because that information is not necessary to the Commission's review of security issuances. Similarly, the reference to the Form No. 1's "Statement B, 'Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization and Depletion,'" is also eliminated from Exhibit D because that is the form in which the now deleted plant schedule data would have been reported.

(5) Section 34.7 (Number of copies to be filed), 131.43 (Report of Securities Issued), and 131.50 (Certificate of Notification) are revised to reduce from five to four the number of copies of documents (in addition to the original) required to be filed with the Commission.

III. Effective Date

Immediate adoption of the revisions to Part 34 of the Commission's regulations will promote an expeditious reduction of unnecessary reporting burdens. Therefore, under 5 U.S.C. 553(d), the Commission is making these changes effective immediately for applications filed after October 7, 1981.

(Department of Energy Organization Act, (42 U.S.C. 7101–7352); E.O. 12009, 3 CFR 142; Federal Power Act, (16 U.S.C. 792–828(c)); Public Utility Regulatory Policies Act, (16 U.S.C. 2601–2635))

In consideration of the foregoing, the Commission amends Part 34 of Chapter I, Title 18 of the Code of Federal Regulations, as set forth below, effective October 7, 1981.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,299]

46 F. R. 50517 (October 14, 1981);
46 F. R. 55952 (November 13, 1981)

18 CFR Part 35

[Docket No. RM81-41]

Sales of Electric Power to the Bonneville Power Administration; Filing of Rate Schedules; Interim rule

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Interim rule.

SUMMARY: Under the Pacific Northwest Electric Power Planning and Conservation Act, the Bonneville Power Administration must develop and file with the Commission for review and approval an "average system cost" methodology for sales of electric power made by electric utilities to the Bonneville Power Administration.

Some utilities that will use the methodology are subject to this Commission's jurisdiction under the Federal Power Act and must file rate schedules pursuant to Part 35 of the Commission's rules. The Commission is amending, on an interim basis, its rules governing the sales of electric power as they may pertain to such utilities and is granting conditional interim approval to the average system cost methodology filed with the Commission by the Bonneville Power Administration. Interim approval of the methodology will permit immediate implementation of the purchase and sale power exchange established in the Pacific Northwest Electric Power Planning and Conservation Act.

DATES: This interim rule is effective October 1, 1981. Comments must be submitted on or before November 13, 1981. Comments of the joint state board must be submitted on or before December 14, 1981.

ADDRESSES: All comments must be mailed to:

Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426

Hon. A. J. Benedetti, Commissioner, Washington Utilities and Transportation Commission, Mail Stop PB&2, Highways-Licenses Building, Olympia, Washington 98504

Hon. Thomas J. Schneider, Commissioner, Montana Public Service Commission, 1227 Eleventh Avenue, Helena, Montana 59601

Hon. Richard S. High, Commissioner, Idaho Public Utilities Commission, 472 West Washington Street, Boise, Idaho 83720

Hon. John J. Lobdell, Commissioner, Oregon Public Utilities Commission, 300 Labor and Industries Building, Salem, Oregon 97310

Hon. Ernst Liebman, Administrative Law Judge, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426

All comments should refer to Docket No. RM81-41.

Copies of the materials submitted by the Bonneville Power Administration to the Commission include (1) Administrator's Record of Decision—Average System Cost Methodology; (2) Residential Purchase and Sale

Agreement; (3) Exhibit A—Wholesale Power Rate Schedules and General Rate Schedule Provisions; (4) Exhibit B—General Contract Provisions; and, (5) Exhibit C—Average System Cost Methodology. Copies of these materials are available for public inspection at:

Federal Energy Regulatory Commission, Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426

Idaho Public Utilities Commission, Commission Secretary's Office, 472 West Washington Street, Boise, Idaho 83720

Washington Utilities and Transportation Commission, Office of the Secretary, 7th Floor, Highways—Licenses Building, Olympia, Washington 98504

Montana Public Services Commission, Office of the Secretary, 1227 Eleventh Avenue, Helena, Montana 59601

Oregon Public Utilities Commission, Room 330, Labor and Industries Building, Salem, Oregon 97310

In addition, copies of materials described above are available from the BPA by contacting Donna L. Geiger, Public Involvement Coordinator, Bonneville Power Administration, P.O. Box 12999, Portland, Oregon 97212; the telephone number is (503) 234–3361, ext. 4261. BPA maintains toll-free lines for use by persons within the region. Oregon callers may use 1–800–452–8429; callers in Washington, Idaho, Montana, Wyoming, Utah, Nevada, and California may use 1–800–547–6048. Messages and requests for information received after normal business hours (after 4:30 p.m. and before 7:30 a.m.) may be recorded on the toll-free lines. These materials are also available for public inspection at the BPA Office of Public Involvement 1002 Northeast Holladay, Area 494, Portland, Oregon 97232.

FOR FURTHER INFORMATION CONTACT: Michael Kessler, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357–5227.

SUPPLEMENTARY INFORMATION:

A. Introduction

October 1, 1981.

The Federal Energy Regulatory Commission (Commission) is amending, on an interim basis, its rules that govern the sale of electric power (18 CFR Part 35) to provide for certain sales made under the provisions of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act).[1] Specifically, the Commission is adding a new § 35.13a to: (1) Provide for the filing of rate schedules for sales of electric power made by Pacific utilities to the Bonneville Power Administration (BPA) under Section 5(c) of the Northwest Power Act and (2) approve conditionally the average system cost methodology, with which those rates schedules must conform, as developed by the BPA and filed with the Commission.

The rule, including conditional approval of the average system cost methodology, is being instituted on an interim basis in response to a petition filed with the Commission by the BPA. Comments on both the rule and the methodology are requested.

B. Background

Among the purposes of the Northwest Power Act is "to assure the Pacific Northwest of an adequate, efficient, economical and reliable power supply."[2] To effectuate that purpose, the Act establishes rules and procedures governing the purchase and sale of electric power by the BPA to, or from, the region's electric utilities and the BPA's direct service industrial customers.[3] Section 5(c) of the Act provides for power exchanges for service to the residential customers of regional electric utilities.

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[1] Pub. L. No. 96-501, 94 Stat. 2697 (1980).

[2] Section 2(2) of the Northwest Power Act, 94 Stat. 2697 (1980).

[3] The "region" is defined under section 3(14) of the Northwest Power Act to mean:

Under section 5(c), after October 1, 1981, any regional utility can sell electric power to the BPA at the utility's "average system cost" of producing that power, that cost to be determined by the Administrator of the BPA on the basis of a methodology developed for this purpose.[4] In return, the BPA is required to sell an equivalent amount of power back to the utility at a rate identical to that which preference cutomers pay BPA for power to meet general requirements. The rate charged by the BPA to the utility would generally be lower than the rate charged by the utility to the BPA.

It is anticipated that this exchange agreement will be used primarily by the region's investor-owned utilities. The exchange will allow residential and some small electric power consumers to purchase power from participating investor-owned utilities at a lower rate than they would otherwise pay. In this manner, these consumers will "share in the economic benefits of the lower-cost Federal resources marketed by BPA and will provide these consumers wholesale rate parity with residential consumers of preference utilities in the region."[5] The BPA's direct-service industrial customers will bear the costs of the exchange in return for the opportunity to purchase long term power from the BPA.[6]

Under the terms of the Northwest Power Act, the Commission has a limited, but important, role to play in implementing the residential power exchange agreement provisions. First the Commission must review and approve the average system cost methodology developed by the Administrator of BPA.[7] Second, under the Federal Power Act, the Commission must exercise its jurisdiction over the rates charged by public utilities selling power to the BPA under the exchange agreement and the average system cost methodology developed for that exchange.

After the initial consultation process, the BPA developed, and noticed for public comment, a proposed average system cost methodology.[8] In addition, the BPA held a public hearing on the proposed methodology on June 8, 1981 in Portland, Oregon. After the comment process, the proposed methodology was revised in light of the comments. The revised methodology was then filed with the Commission on August 27, 1981.

On September 24, 1981, the BPA petitioned the Commission for the interim approval of the average system cost methodology filed on August 27,

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(T)he area consisting of the States of Oregon, Washington, and Idaho, the portion of the State of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River drainage basin; and * * * which are a part of the service area of a rural electric cooperative customer serviced by the Administrator on the effective date of this Act which has a distribution system from which it serves both within and without such region.

[4] *See* Section 5(c) of the Northwest Power Act, 94 Stat. 2711 (1980). The methodology is to be developed with a Council (defined under Section 4(a)(1) of the Act, 94 Stat. 2700–2701 (1980)), BPA customers and appropriate State regulatory bodies. *Id.*

[5] S. Rep. No. 96-976, Part III, 96th Cong., 2d Sess. at 35; *See also* H.R. Rep. No. 96-976, Part II, 96th Cong., 2d Sess. at 35.

[6] *Id.* The specific provision for this is section 7(c) of the Northwest Power Act, 94 Stat. 2725 (1980).

[7] In anticipation of the BPA's filing, and pursuant to section 209 of the Federal Power Act and regulations promulgated thereunder, (18 CFR 1.37), the Commission, by letter dated May 15, 1981, appointed members to the Joint State Board from nominations submitted by each of the participating states. The State representatives to the Joint State Board are: Thomas J. Schneider, of Montana PSC, Member; Howard L. Ellis, of Montana PSC, Alternate; Richard S. High, of Idaho PUC, Member; Conley Ward, Jr., of Idaho PUC, Alternate; John J. Lobdell, of Oregon PUC, Member; Gene Maudlin, of Oregon PUC, Alternate; A. J. Benedetti, of Washington UTC, Member; and Robert W. Bratton, of Washington, UTC, Alternate. In addition, the Commission appointed Judge Ernst Liebman, Commission Administrative Law Judge, as its representative on, and presiding federal member of, the Board.

On July 9, 1981, the members of the Board met in Seattle, Washington to discuss procedural matters and to receive a briefing from representatives of the BPA on the proposed average system cost methodology. Notice of the meeting, which was open to the public, was issued on June 17, 1981.

[8] 46 FR 32727 (June 24, 1981).

1981, requesting that the approval be effective on October 1, 1981. In the petition, the BPA also requested waiver of the 60-day notice provision of the Federal Power Act (16 U.S.C. 824d) for rates that relied on that methodology to be filed by investor-owned utilities with the Commission, the suspension of such rates for one day, and the approval of such rates, subject to adjustment, as of October 1, 1981.

In support of its petition, the BPA stated that its offer of residential purchase and sales contracts to investor-owned utilities had been accepted by some of these utilities who have either filed, or are about to file, those contracts with the Commission, to be effective October 1, 1981. The contracts will implement the residential sales exchanges of section 5(c) of the Northwest Power Act. In addition, BPA states that contracts to certain direct-service industries, as well as BPA's rate for power delivered to investor-owned utilities under the exchange contracts, are not in effect, the latter in effect on an interim basis.*

C. Discussion

For the reasons discussed below, the Commission has determined to conditionally grant the BPA's petition with respect to interim approval of the average system cost methodology and to deny the petition with respect to waiver of notice of rate filing requirements, advance suspension of rates and approval of rates subject to refund. Although the Commission is inclined to agree in principle with the BPA's requests relating to notice, suspension, and approval of rates, it will consider such requests only in connection with rates actually filed with the Commission.

1. *The average system cost methodology.* The Commission is unable to finally approve the average system cost methodology by October 1, 1981. The Commission has determined to seek the advice of a Joint Board in its review of the methodology. In addition, the methodology itself must be fully reviewed by the Commission before final approval can be given. These procedures could not be completed during the short time period in which the methodology has been before the Commission.

Because the Commission cannot grant final approval by October 1, 1981, its alternatives are to grant the BPA's petition for interim approval of the methodology or to deny the petition. To grant the petition would be to approve the methodology without conducting the type of in-depth review that the Commission believes is its responsibility under the statute; to deny the petition would be to delay in whole or in part the implementation of the residential exchange provided for under the statute. On balance, the Commission has decided to grant the petition, with certain conditions, for the following reasons.

First, such approval is necessary to further the intent of the Northwest Power Act. An approved (by the Commission) average system cost methodology is fundamental to the residential exchange of section 5 of the Act. The methodology defines the rates at which sales will be made to the BPA which, if made, permit the exchange to go forward. The Act provides that these sales (and therefore the exchange) can take place as early as October 1, 1981. The BPA has shown in its petition that it, as well as affected utilities, stand ready to inaugurate exchanges by that date.

Second, an approved average system cost methodology will serve to protect the BPA and its customers from monetary losses that may be occasioned through the exchange sales made between the BPA and the utilities who sell under rates established by the methodology. The differences in rates charged by, and to, the BPA under the exchanges will be recouped through BPA sales of electric power made to participating direct service industrials. Those differences will be predicated, in no small part, upon the average system cost methodology. It is that methodology which principally governs the rates charged the BPA by utilities which, in turn, is a prime determinant of the differences to be recouped by the BPA from its direct service industrial customers. If the BPA does not make such recoupment, it stands to lose what could become a large sum of money.

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*BPA also points out that at least two investor-owned utilities, in reliance on BPA's filing and in contemplation of reduced rates for their customers under the exchange contracts, have filed for reductions in retail residential tariffs with their state regulatory authorities and that their reductions have been granted effective October 1, 1981.

These two reasons warrant the immediate approval of the BPA's average system cost methodology. However, the Commission is obligated to review and approve that methodology in accordance with certain procedures and its responsibilities to protect the public interest. The Commission has yet to finish its review of the methodology as filed. For these reasons, the approval granted in this rule is interim only.

Moreover, that interim approval must be conditioned to ensure that the public interest is protected during the time period the interim approval is in place. The average system cost methodology will affect rates paid by, and to, the BPA. To the extent that the methodology finally approved by the Commission differs from that filed by the BPA on August 24, 1981, and which is herein approved on an interim basis, the rates paid may be different. The Commission must be assured that such difference is corrected, through reimbursement or refund, to the extent of the difference. There should be no disparity between rates paid under the interim-approved methodology and those that would have been paid had the final methodology been used instead. To ensure this result, the Commission makes the approval of the methodology conditional upon there being, through contract or the methodology itself, a system for refund or reimbursement.

The Commission attaches this condition with full awareness that, by so doing, uncertainty is injected into the exchange process. Rates paid may be too high or too low, depending upon the average system cost methodology finally approved by the Commission. However, under the circumstances, some uncertainty is unavoidable. The Commission staff has completed a preliminary review of the methodology and is satisfied that such uncertainty is minimal. Moreover, the methodology is a product not only of the statutorily prescribed process of consultation between the BPA and affected entities, but also of notice and comment procedures. This too should serve to minimize any uncertainty and, in addition, provides good grounds for finding that, for purposes of interim approval, due process has been observed.

2. *Rate approval.* The BPA seeks advanced approval of rates that will be filed with the Commission by jurisdictional utilities who sell power to the BPA and whose rates are based upon the average system cost methodology. The Commission cannot grant such approval in advance of the actual filing of a rate. The Commission will act promptly on such rate filings.

In addition, the Commission is amending its regulations under Part 35 to allow for the consideration of rates filed under the average system cost methodology. These amendments are being made effective immediately and on an interim basis. Through them, such rate filings may be expeditiously handled. They provide for waivers of such parts of the Commission's regulations as may be inconsistent with a rate filed under the average system cost methodology.

D. Public Comment Procedures

The Commission seeks public comment on this interim rule, including the interim approval of the BPA's average system cost methodology. All comments will be considered before issuance of a final rule and final approval of an average system cost methodology.

Copies of all the materials submitted by the BPA to the Commission include: (1) Administrator's Record of Decision—Average System Cost Methodology; (2) Residential Purchase and Sale Agreement; (3) Exhibit A—Wholesale Power Rate Schedules and General Rate Schedule Provisions; (4) Exhibit B—General Contract Provisions; and, (5) Exhibit C—Average System Cost Methodology. Copies of these materials are available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426.[10]

In addition, copies of all materials described above are available from the BPA by contacting Donna L. Geiger, Public Involvement Coordinator, Bonneville Power Administration, P.O. Box 12999, Portland, Oregon 97212; the telephone number is (503) 234–3361, ext. 4261. BPA maintains toll-free lines for use by persons within the region. Oregon callers may use 1–800–452–8429; callers in Washington, Idaho, Montana, Wyoming, Utah, Nevada, and California may use 1–800–547–6048. Messages and requests for information received after normal business hours (after 4:30 p.m. and before 7:30 a.m.) may be recorded on the toll-free lines. These materials are also available for public inspection at the BPA Office of Public Involvement, 1002 Northeast Holladay, Area 494, Portland, Oregon 97232.

Copies of all materials described above are available for public inspection at the state commissions listed below:

Idaho Public Utilities Commission, Commission Secretary's Office, 472 West Washington Street, Boise, Idaho 83720

Washington Utilities and Transportation Commission, Office of the Secretary, 7th Floor, Highways-Licenses Building, Olympia, Washington 98504

Montana Public Service Commission, Office of the Secretary, 1227 Eleventh Avenue, Helena, Montana 59601

Oregon Public Utilities Commissioner, Room 330, Labor and Industries Building, Salem, Oregon 97310

A summary of issues regarding the methodology is attached as Appendix A. Interested persons are invited to submit written comments on the interim rule, the interim methodology and the Residential Purchase and Sale Agreement to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426. Comments should refer to Docket No. RM81–41.

Each of the issues presented in the written comments should appear in a separate section. Fourteen copies should be submitted with the original. All comments received by the Commission by November 13, 1981, will be considered prior to the promulgation of the final rule.

In addition, two copies of comments should be filed by November 13, 1981, with each of the members of the Joint Board listed below:

Hon. A. J. Benedetti, Commissioner, Washington Utilities and Transportation Commission, Mail Stop PB&2, Highways-Licenses Building, Olympia, Washington 98504

Hon. Thomas J. Schneider, Commissioner, Montana Public Service Commission, 1227 Eleventh Avenue, Helena, Montana 59601

Hon. Richard S. High, Commissioner, Idaho Public Utilities Commission, 472 West Washington Street, Boise, Idaho 83720

Hon. John J. Lobdell, Oregon Public Utilities Commissioner, 300 Labor and Industries Building, Salem, Oregon 97310

Hon. Ernst Liebman, Administrative Law Judge, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426

The Joint Board shall have until December 14, 1981, to file its recommendation and responses, either individually or as the Board, or both, with the Commission.

Written comments will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426.

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[10] Exhibit D—Residential Load Definition was filed by the BPA separately.

E. Effective Date

In accordance with the provisions of 5 U.S.C. 553 (b) and (d), the Commission finds good cause, for the reasons discussed above, to make this rule effective upon issuance without prior notice and comment.

(Pacific Northwest Electric Power Planning and Conservation Act, Pub. L. No. 96–501, 94 Stat. 2697 (1980); Federal Power Act, as amended, (16 U.S.C. 792–828c); Department of Energy Organization Act, (42 U.S.C. 7101–7552); E. O. 12009, 3 CFR 142 (1978))

In consideration of the foregoing, the Commission amends Part 35, Chapter I of Title 18 of the *Code of Federal Regulations* as set forth below, effective upon issuance.

By the Commission.

Lois D. Cashell,
Acting Secretary.

Appendix A

On August 27, 1981, the Bonneville Power Administration (BPA) tendered for review and approval its proposed Average System Cost Methodology (hereinafter ASC Methodology) required by the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act). Section 5(c)(7) of the Regional Act requires the BPA Administration to develop an ASC Methodology through a consultation process. That has been completed. The ASC Methodology is used to determine a utility's cost of power for purposes of the power exchange allowed by the Regional Act between a utility and BPA. Under the exchange, BPA's preference power rate is passed through to residential customers of an exchanging utility, generally resulting in lower electric rates for those customers.

Pursuant to section 5(c)(7) of the Regional Act, the Administrator's proposed ASC methodology has been submitted to the Federal Energy Regulatory Commission for its review and approval. The major issues that developed during the consultation and were decided regarding the ASC Methodology are set forth below.

1. Jurisdictional Costing Approach

The issue was whether the ASC Methodology should provide for the independent establishment of the basic cost and other data needed to calculate an ASC, or whether the findings made by retail rate setting bodies should be used in determining ASC. Agreement was reached that the costs allowed or established for retail ratemaking purposes should be used, subject to certain specific requirements, in calculating ASC.

2. Functionalization Procedure

a. General functionalization—Calculation of ASC requires a separation (or functionalization) of costs since only the exchanging utility's production and transmission costs are relevant to the exchange transaction. Other activities and costs, primarily those associated with the distribution of electric power, are not undertaken or incurred because of the exchange. The three steps in the functionalization process are: (1) The use of Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts; (2) reliance on analytical studies prepared by the exchanging utility which demonstrate the functional nature of an item; and (3) use of several footnotes which specify functionalization treatment, either by use of a formula or by direct functionalization to a specific category.

b. Revenue related taxes—Following the publication of the initial proposal and during the review of the Pacific Power and Light (PP&L) sample, concerns arose as to the treatment of revenue-related taxes. Specifically, in the PP&L sample the test-year costs related to the State of Washington's Business and Occupation (B&O) tax (collected pursuant to Wash. Rev. Code § 82.04.240 et. seq. and 82.16.020) were functionalized based on the functionalization of the total revenue requirement. The B&O tax in question is applied to the retail sales revenue of PP&L.

The BPA believes it is more appropriate to functionalize expenses incurred at the retail level to

[The next page is 31,679-3]

distribution/other. Therefore, BPA has adopted a functionalization footnote (see footnote 3) requiring that revenue taxes related to retail sales, and other items unrelated to the power supply level such as bad debt expense, be functionalized to distribution/other.

3. Losses

It was initially agreed that distribution losses would be established pursuant to an engineering study. The initial footnote associated with this subject was determined to be too vague, and a more precise definition for loss justification was substituted in the footnote.

4. Treatment of In-Lieu Taxes

During the Consultation process concern was expressed with regard to the treatment of in-lieu taxes included in the retail rates of publicly owned utilities. It was felt that local governments would have an incentive to increase in-lieu taxes paid by locally owned and operated utilities participating in the exchange, thus putting the burden of paying these additional taxes on the region's ratepayers through the exchange. The investor-owned utility customers (IOU's) and direct-service industrial customers (DSI's) felt in-lieu taxes should be included in the ASC calculations, but only to the extent that nontax-exempt utilities would pay these taxes for the various levels of local government. To alleviate the concerns expressed, a footnote (footnote 14) was agreed to and included in the methodology limiting the in-lieu taxes to those which were actually paid and to an amount comparable to what the actual tax would have been.

5. Extent of BPA Review

Although the requirement for using the findings of the Commission approving retail rates significantly reduces the depth of review needed for a utility's calculation of its ASC, the parties agreed that BPA should review the filed ASC determination for consistency with the provisions of the ASC methodology, and make an adjustment where an inconsistency is found.

6. Treatment of Secondary and Miscellaneous Service Sales Revenues

The ASC Methodology will credit a utility's secondary and miscellaneous services revenues against its eligible exchange costs before deriving its Contract System Costs. For utilities operating in multiple jurisdictions, the ASC Methodology will use the allocations of the appropriate commissions to determine the proper amount of secondary and miscellaneous services revenues. Where a new large single load is served by an excluded resource, the ASC Methodology will proportionately credit secondary revenues between eligible and excluded resources. Secondary revenues will be functionalized entirely to production. Miscellaneous services will be functionalized according to the nature of the service. Although other treatments were proposed, the BPA Administrator determined that since a utility receives the benefit of BPA's secondary and miscellaneous service sales, it is appropriate that BPA receive the same benefits from a utility.

7. Billing Credits

Section 6(h) of the Regional Act provides for payment of billing credits to BPA customers for conservation measures or building resources which decrease BPA's service obligations. There were three proposed treatments of conservation costs and corresponding billing credit revenues in the ASC methodology. The cost of the conservation program could be included in Contract System Costs with no offset from the revenues. This treatment would provide the maximum incentive for utilities to undertake conservation. However, it would result in BPA paying twice for the conservation program, first in the form of the billing credit and second in the ASC rate.

A second alternative would be to credit all the billing credit revenues against Contract System Costs. Proponents of this alternative assert that billing credits should be treated for ASC purposes in the same manner as opportunity revenues, and as they are used in establishing retail rates.

Residential ratepayers from exchanging utilities would benefit only as the whole region benefits from a conservation program.

The ASC Methodology provides that the way to treat billing credit revenue, to credit them against Contract System Costs, only up to the cost of the corresponding conservation program. Another way of stating this proposal is that both the costs of the conservation program and all billing credit revenues are excluded from Contract System Costs. This treatment is consistent with two purposes of the Regional Act—regional wholesale rate parity for residential consumers and the development of cost-effective conservation programs. It also insures that each utility in the region will have the incentive to develop independent conservation programs.

8. Terminated Facilities

Section 5(c)(7)(C) of the Regional Act requires that ASC shall not include "any costs of any generating facility which is terminated prior to initial commercial operation." It was determined that the Regional Act was not retroactive regarding costs of terminated facilities (i.e., costs of a generating facility terminated prior to the effective date of the Regional Act may be included in a utility's ASC). It was also determined that construction work in progress (CWIP) may be allowed in ASC, but it is recoverable under the following circumstances: If the CWIP included in the rate base is associated with a specific generating facility and that facility is later terminated, then BPA will recover all payments made resulting from that CWIP inclusion, if the CWIP included is not identified with particular plants, BPA will recover revenue only to the extent the CWIP included cannot be identified with plant other than terminated facilities.

9. Return on Equity for Public Agencies

Other treatments were proposed, but the ASC Methodology provides that a publicly-owned utility be allowed a return on equity equal to that needed to protect its credit rating. In no case shall the return on equity for ASC purposes be higher than that included in the utility's retail rates. The proposal allows the utility to earn revenues to meet its debt coverage and equity needs while protecting the region from higher than necessary profits being included in ASC.

10. New Large Single Load

Section 5(c)(7) of the Regional Act specifies that average system costs shall not include the costs of additional resources in an amount sufficient to serve any new large single load of a participating utility.

"New Large Single Load" is defined as any load associated with a new facility, an existing facility, or an expansion of an existing facility which (a) is not contracted for, or committed to, by a public body, cooperative, investor-owned utility, or Federal agency customer prior to September 1, 1979, and (b) will result in an increase in a customer's power requirements of 10 average megawatts or more in any consecutive 12-month period.

The costing of resources associated with new large single loads is complicated by the fact that generating and bulk transmission facilities are rarely identified with particular loads. Instead a utility serves all its load with all of its resources at melded rates.

The ASC Methodology provides that to the extent the utility has the following resources, the cost of serving new large single loads will be the cost (in the following priority) of: (1) Resources dedicated to the load; (2) power purchased from BPA at the New Resources (7)(f) rate; (3) a pool of the utility's resources not committed to its load as of September 1, 1979; and (4) the most recently acquired other baseload resource or long-term power purchase.

Appendix 1—Average System Cost Methodology; Instructions

Exhibit C—Appendix 1 is the form on which a Utility participating in a Residential Purchase and Sale Agreement shall report its Contract System Costs and other necessary data for the calculation of ASC.

The form consists of six schedules that shall be completed by the Utility in accord with these instructions and the provisions of the footnotes following the schedules. Any items not applicable to the Utility shall be so identified.

The schedules are as follows:

Schedule:
1—Plant Investment/Rate Base/Rate-of-Return
2—Capital Structure and Cost of Capital
3—Expenses
4—Income Taxes
5—Average System Cost
6—Total Utility and Jurisdictional Results of Operations

The filing Utility shall reference and attach workpapers that support Costs, including details of allocation and functionalization.

All references to the FERC accounts are to the FERC Uniform System of Accounts as of October 1, 1981. The Costs includable in the attached schedules are those includable by reason of the definitions in the FERC accounts. If the FERC accounts are later revised or renumbered, any changes shall be incorporated into this form by reference, except to the extent that Bonneville, upon a showing of good cause, demonstrates that a particular change results in a substantial change in the type of Costs allowable for exchange purposes. If the Utility does not follow the FERC accounts, its filing must include a reconciliation between its accounts and the items allowed as Contract System Costs.

Bonneville may require the Utility to account for purchase power transactions with affiliated entities as though the affiliated entities were owned in whole or in part by the utility, if necessary to properly determine and/or functionalize the utility's costs.

A Utility operating in more than one Jurisdiction shall allocate its total system costs among Jurisdictions in accord with the same allocation methods and procedures used by the Commission to establish jurisdictional Costs and resulting revenue requirements. Appendix 1 shall include details of the allocation. This allocation also accomplishes the exclusion of the Costs of additional resources to meet loads outside the region, as required by section 5(c)(7) of the Regional Act.

All schedule entries and supporting data shall be in accord with generally accepted accounting principles and practices as these principles and practices apply to the electric utility industry.

Appendix 1
Schedule 1

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology

Plant Investment/Rate Base/Rate-of-Return
Jurisdiction - ____________

					Functionalization			
Line No.	Items/FERC Accounts/Footnotes (1)	Jurisdiction Total (2)	Excluded Amount (3) 15b & c/	Total To Be Functionalized (4)	Production (5)	Transmission (6)	Total for Exchange (7)	Other (8)
1	Plant-in-Service/310-373 1/ 7/ 8/							
2	General Plant/389-399 2/							
3	Intangible Plant/301-303 3/							
4	CWIP/107, 120.1 3/							
5	Acquisition Adjustment/114 3/							
6	Total Gross Plant							
7	Less:							
8	PIS Depreciation Reserve/108 1/ 4/							
9	General Plant Depreciation Reserve/108 4/							
10	Accumulated Amortization/111, 115 4/							
11	Total Plant Deductions							
12	Total Net Plant							
13	Plant Held for Future Use/105 3/							
14	Nuclear Fuel/120.2-120.4 Less 120.5 1/							
15	Accumulated Deferred Debits/186 3/							
16	Less:							
17	Customer Advances/252 19/							
18	Accumulated Deferred Investment Tax Credits/255 3/							
19	Accumulated Deferred Income Taxes/281-283 3/							
20	Other Accumulated Deferred Credits/253, 256-257 3/							
21	Total Net Accumulated Deferred Debits/Credits							
22	Cash Working Capital/Various 6/							
23	Materials and Supplies/151-157, 163 3/							
24	Other/105, 124, 184, Various 3/ 20/							
25	Total Rate Base							
26	Times Rate-of-Return @ ______% 16/ 17/							

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Appendix I
Schedule IA

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology

					Functionalization			
Line No.	Items (1)	Jurisdiction Total (2)	Excluded Amount (3) 15b & c/	Total To Be Functionalized (4)	Production (5)	Transmission (6)	Total for Exchange (7)	Other (8)
			Rate Base Summary Jurisdiction -					
1	Utility Plant-in-Service							
2	Less: Accumulated Provision for Depreciation and Amortization							
3	Net Utility Plant-in-Service							
4	Construction Work in Progress							
5	Plant Held for Future Use							
6	Utility Plant Acquisition Adjustments							
7	Nuclear Fuel							
8	Customer Advances for Construction							
9	Materials and Supplies							
10	Cash Working Capital							
11	Unamortized Leasehold Improvements and Other Miscellaneous Deferred Items							
12	Weatherization-Interest Free Loans							
13	Extraordinary Property Losses							
14	Total Rate Base							
			Electric Plant-In-Service Jurisdiction -					
1	Intangible Plant							
	Production Plant:							
2	Steam Production Plant							
3	Nuclear Production Plant							
4	Hydraulic Production Plant							
5	Other Production Plant							
6	Total Production Plant							

Electric Plant-In-Service Jurisdiction -

—Continued

7 Transmission Plant
8 Distribution Plant
9 General Plant
10 Total Electric Plant-In-Service

Reserve for Depreciation and Amortization of Electric Plant-In-Service Jurisdiction -

Depreciation Reserve
Production Plant:
1 Steam Production
2 Nuclear Production
3 Hydraulic Production
4 Other Production
5 Transmission
6 Distribution
7 General
8 Total Depreciation Reserve
9 Amortization Reserve
10 Total Depreciation and Amortization Reserve

Note: 1. Supporting workpapers are to be attached.
2. Footnotes referenced on Schedule 1 will be relied upon in determining ASC.

Appendix 1
Schedule 2

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology

Capital Structure and Cost of Capital
Jurisdiction -

Line No.	Items/Footnotes (1)	Amount (2)	Ratio (3)	Component Cost (4)	Weighted Cost (5)
1	Debt				
2	Preferred Stock				
3	Common Equity				
4	Deferred Income Taxes 10/				
5	Deferred Investment Tax Credit 10/				
6	Total Weighted Cost				

Schedule 2A

Debt Summary 11/
Jurisdiction -

Line No.	Items	Date of Issue (1)	Date of Maturity (2)	Interest Rate (3)	Face Amount (4)	Premium (5)	Discount (6)	Issue Expense (7)	Net Proceeds (8)	Interest Expense (9)

Schedule 2B

Preferred Stock Summary
Jurisdiction -

Line No.	Items	Shares Issued (1)	Dividend Rate (2)	Outstanding Balance (3)	Premium (4)	Issue Expense (5)	Net Proceeds (6)	Dividends (7)

Appendix 1
Schedule 3

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology

Expenses
Jurisdiction -

Line No.	Items/FERC Accounts/Footnotes (1)	Jurisdiction Total (2)	Excluded Amount 15b & c/ (3)	Total To Be Functionalized (4)	Functionalization Production (5)	Functionalization Transmission (6)	Functionalization Total For Exchange (7)	Functionalization Other (8)
1	Production:							
2	Fuel/501, 518, 547 1/							
3	Purchased Power/555 1/							
4	Other/500, 502-517, 519-546, 548-577 1/							
5	Transmission/560-573 1/ 4/							
6	Distribution/580-598 1/ 4/							
7	Customer Accounting/901-905 19/							
8	Customer Assistance/907-910 21/							
9	Admin. & General/920-932 12/							
10	Total Operations & Main.							
11	Depreciation & Amortization/ 403-407 1/ 4/							
12	Taxes Other than Federal Income/ 408, 409.1 3/ 4/ 13/ 14/							
13	Federal Income Tax/409.1, 410.1, 411.1, 411.4 9/							
14	Other/411.6, 411.7 3/							
15	Less:							
16	Nonfirm Sales for Resale Rev./447 22/							
17	Other Operating Rev./450-456 3/ 25/							
18	Billing Credits 5/							
19	Total Operating Expenses							
20	Return from Schedule 1							
21	Less Subsidiary Income							
22	Total Cost 18/							

Appendix 1
Schedule 3A

Electric Operating Expenses
Jurisdiction -

	POWER PRODUCTION EXPENSES
	Steam Power Generation:
1	Operation
2	Fuel
3	Other
4	Maintenance
5	Total Steam Power Generation
	Nuclear Power Generation:
6	Operation
7	Fuel
8	Other
9	Maintenance
10	Miscellaneous Nuclear Research
11	Total Nuclear Power Generation
	Hydraulic Power Generation:
12	Operation
13	Maintenance
14	Total Hydraulic Power Generation
	Other Power Generation:
15	Operation
16	Maintenance
17	Total Other Power Generation

Appendix 1
Schedule 3A

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology

Electric Operating Expenses
Jurisdiction - __________ *

						Functionalization			
Line No.	Items (1)	Jurisdiction Total (2)	Excluded Amount (3)	15b & c/*	Total To Be Functionalized (4)	Production (5)	Transmission (6)	Total for Exchange (7)	Other (8)
	Other Power Supply Expenses:								
18	Purchased Power								
19	Other								
20	Total Other Power Supply Expenses								
21	Total Power Production Expenses								
	TRANSMISSION EXPENSES								
22	Operation								
23	Wheeling								
24	Other								
25	Maintenance								
26	Total Distribution Expenses								
	DISTRIBUTION EXPENSES								
27	Operation								
28	Maintenance								
29	Total Distribution Expenses								
30	CUSTOMER ACCOUNTS EXPENSES								
31	CUSTOMER SERVICE AND INFORMATION EXPENSES								
	ADMINISTRATIVE AND GENERAL EXPENSES								
32	Operation								
33	Maintenance								
34	Total Administrative and General Expenses								
35	TOTAL ELECTRIC OPERATING EXPENSES								

Appendix 1
Schedule 3B

Depreciation and Amortization Accrual
Jurisdiction - ____________________

	Depreciation:
1	Steam Production Plant
2	Nuclear Production Plant
3	Hydraulic Production Plant
4	Other Production Plant
5	Transmission Plant
6	Distribution Plant
7	General Plant
8	Total Depreciation
9	Amortization of Limited-Term Plant
10	Amortization of Utility Plant Acquisition Adjustments
11	Amortization of Property Losses
12	Total Depreciation and Amortization Accrual

Note: 1. Supporting workpapers are to be attached.
2. Footnotes referenced on Schedule 3 will be relied upon in determining ASC.

Appendix 1
Schedule 3C

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology

Taxes Other Than Federal Income Taxes
Jurisdiction - .

Line No.	Items (1)	Jurisdiction Total (2)	Excluded Amount (3) 15b & c/	Total To Be Functionalized (4)	Functionalization			
					Production (5)	Transmission (6)	Total for Exchange (7)	Other (8)
1	FEDERAL - Insurance Contributions							
2	- Unemployment							
	STATE							
3	California - Property							
4	- Unemployment							
5	Oregon - Property							
6	- Tri-Met							
7	- Lane County							
8	- Unemployment							
9	- Regulatory Commission							
10	Washington - Property							
11	- Unemployment							
12	- Generating Tax							
13	- Pollution Control Credit							
14	Idaho - Property							
15	Montana - Property							
16	- Unemployment							
17	Wyoming - Property							
18	- Unemployment							
19	Utah - Property							
20	LOCAL - Occupation and Franchise							
21	STATE INCOME TAXES							
22	IN-LIEU TAXES							
23	OTHER							
24	TOTAL							

Note: 1. Supporting workpapers are to be attached.
2. Footnotes referenced on Schedule 3 will be relied upon in determining ASC.

Appendix 1
Schedule 4

Income Taxes
Jurisdiction - __________

1 Federal Income Taxes

2 Deferred Income Taxes

3 Income Taxes Deferred in Prior Years

4 Investment Tax Credit Adjustment

5 Total Federal Taxes

Appendix 1
Schedule 4A

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology

Line No.	Items (1)	Jurisdiction Total (2)	Federal Taxes on Income Jurisdiction -			Functionalization			
			Excluded Amount (3)	15b & c/*	Total To Be Functionalized (4)	Production (5)	Transmission (6)	Total for Exchange (7)	Other (8)
	INCOME								
1	Operating Revenues								
	Deductions								
2	Operating and Maintenance Expense								
3	Depreciation Expense								
4	Amortization Expense								
5	Taxes Other Than Federal Income Taxes								
6	Interest Expense								
7	Total Deductions								
8	Net Income Before Federal Income Tax								
	TAX ADJUSTMENTS								
9	Book Depreciation								
10	Tax Depreciation								
11	Charges to Construction								
12	Coal Depletion								
13	Other Adjustments								
	1.								
	2.								
	.								
	.								
	.								
14	Total Tax Adjustments								
15	Taxable Income								
16	Preferred Dividends Paid - Credit								
17	Total Taxable Income								
18	Federal Income Tax								
19	Less Investment Credit								
20	Net Federal Income Tax								

Appendix 1
Schedule 4B

		Other Included Items Jurisdiction -
	Operating Revenues:	
1	Nonfirm Sale for Resale/447	
2	1.	
3	2.	
4	3.	
	Other Operating Revenues/450-456	
5	Acct. 450	
6	Acct. 451	
7	Acct. 452	
8	Acct. 453	
9	Acct. 454	
10	Acct. 455	
11	Acct. 456	
12	Total Revenues	
	Other Items:	
13	Investment Tax Credit Adjustment/411.5	
14	Deferred Current Year	
15	Restored Current Year	
16	Restored from Prior Years	
17	Total ITC Adjustment	
18	Deferred Income Tax - Current/410.1	
19	Deferred Income Tax from prior years/411.1	
20	Other Accounts	

Note: 1. Supporting workpapers are to be attached.
2. Footnotes referenced on Schedule 4 will be relied upon in determining ASC.

Appendix 1
Schedule 6

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology

Average System Cost
Jurisdiction - ______________

Line	Items	Amount
1	Contract System Costs:	
2	Production Cost (from Schedule 3)	
3	Transmission Cost (from Schedule 3)	
4	Total Contract System Costs.	
5	Contract System Load:	
6	Total Load (MWh)	
7	Less:	
8	Nonfirm Adjustment (MWh)	
9	Other Adjustments (MWh)	
10	Net Load (MWh)	
11	Plus:	
12	Distribution Losses (MWh) 17/	
13	Total Net Load (MWh)	
14	Less:	
15	Excluded Load (MWh)	
16	Excluded Load Distribution Losses (MWh)	
17	Total Contract System Load (MWh)	
18	Average System Cost (mills/kWh)	

(Line 4 ÷ Line 17).

Appendix 1
Schedule 6A

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology

Electric Plant-In-Service
Jurisdiction -

Line No.	Items (1)	Total Utility (2)	Allocation Basis 15a/ (3)	Jurisdictional Amount (4)
1	Intangible Plant			
	Production Plant:			
2	Steam Production Plant			
3	Nuclear Production Plant			
4	Hydraulic Production Plant			
5	Other Production Plant			
6	Total Production Plant			
7	Transmission Plant			
8	Distribution Plant			
9	General Plant			
10	Total Electric Plant-in-Service			

Appendix 1
Schedule 6B

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology

Reserve for Depreciation and Amortization of Electric Plant-In-Service
Jurisdiction -

Line No.	Items (1)	Total Utility (2)	Allocation Basis 15a/ (3)	Jurisdictional Amount (4)
	Depreciation Reserve			
	Production Plant:			
1	Steam Production			
2	Nuclear Production			
3	Hydraulic Production			
4	Other Production			
5	Transmission			
6	Distribution			
7	General			
8	Total Depreciation Reserve			
9	Amortization Reserve			
10	Total Depreciation and Amortization Reserve			

Appendix 1
Schedule 6C

Rate Base Summary
Jurisdiction - ________

1 Utility Plant-in-Service

2 Less: Accumulated Provision for Depreciation and Amortization

3 Net Utility Plant-in-Service

4 Construction Work in Progress

5 Plant Held for Future Use

6 Utility Plant Acquisition Adjustments

7 Nuclear Fuel

8 Customer Advances for Construction

9 Materials and Supplies

10 Cash Working Capital

11 Unamortized Leasehold Improvements and Other Miscellaneous Deferred Items

12 Weatherization-Interest Free Loans

13 Extraordinary Property Losses

14 Total Rate Base

Appendix 1
Schedule 6b

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology

Electric Operating Expenses
Jurisdiction - ________

Line No.	Items (1)	Total Utility (2)	Allocation Basis 15a/ (3)	Jurisdictional Amount (4)
	POWER PRODUCTION EXPENSES			
	Steam Power Generation:			
1	Operation			
2	Fuel			
3	Other			
4	Maintenance			
5	Total Steam Power Generation			
	Nuclear Power Generation:			
6	Operation			
7	Fuel			
8	Other			
9	Maintenance			
10	Miscellaneous Nuclear Research			
11	Total Nuclear Power Generation			
	Hydraulic Power Generation:			
12	Operation			
13	Maintenance			
14	Total Hydraulic Power Generation			
	Other Power Generation:			
15	Operation			
16	Maintenance			
17	Total Other Power Generation			

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology

Electric Operating Expenses
Jurisdiction —Continued

Line No.	Items (1)	Total Utility (2)	Allocation Basis (3) 15a/	Jurisdictional Amount (4)
	Other Power Supply Expenses:			
18	Purchased Power			
19	Other			
20	Total Other Power Supply Expenses			
21	Total Power Production Expenses			
	TRANSMISSION EXPENSES			
22	Operation			
23	Wheeling			
24	Other			
25	Maintenance			
26	Total Distribution Expenses			
	DISTRIBUTION EXPENSES			
27	Operation			
28	Maintenance			
29	Total Distribution Expenses			
20	CUSTOMER ACCOUNTS EXPENSES			
31	CUSTOMER SERVICE AND INFORMATION EXPENSES			
	ADMINISTRATIVE AND GENERAL EXPENSES			
32	Operation			
33	Maintenance			
34	Total Administrative and General Expenses			
35	TOTAL ELECTRIC OPERATING EXPENSES			

Appendix 1
Schedule 6E

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology

Depreciation and Amortization Accrual
Jurisdiction -

Line No.	Items (1)	Total Utility (2)	Allocation Basis 15a/ (3)	Jurisdictional Amount (4)
1	Depreciation:			
2	Steam Production Plant			
3	Nuclear Production Plant			
4	Hydraulic Production Plant			
5	Other Production Plant			
6	Transmission Plant			
7	Distribution Plant			
8	General Plant			
9	Total Depreciation			
10	Amortization of Limited-Term Plant			
11	Amortization of Utility Plant Acquisition Adjustments			
12	Amortization of Property Losses			
13	Total Depreciation and Amortization Accrual			

Appendix 1
Schedule 6F

Taxes Other Than Federal Income Taxes
Jurisdiction -

1 FEDERAL - Insurance Contributions
2 - Unemployment

STATE
3 California - Property
4 - Unemployment

5 Oregon - Property
6 - Tri-Met
7 - Lane County
8 - Unemployment
9 - Regulatory Commission
10 - Excise

11 Washington - Property
12 - Unemployment
13 - Generating Tax
14 - Pollution Control Credit

15 Idaho - Property

16 Montana - Property
17 - Unemployment

18 Wyoming - Property
19 - Unemployment

20 Utah - Property

21 LOCAL - Occupation and Franchise

22 IN-LIEU TAXES

23 TOTAL

Appendix 1
Schedule 6G

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology

Federal Taxes on Income
Jurisdiction -

Line No.	Items (1)	Total Utility (2)	Allocation Basis 15a/ (3)	Jurisdictional Amount (4)
	INCOME			
1	Operating Revenues			
	DEDUCTIONS			
2	Operating and Maintenance Expense			
3	Depreciation Expense			
4	Amortization Expense			
5	Taxes Other Than Federal Income Taxes			
6	Interest Expense			
7	Total Deductions			
8	Net Income Before Federal Income Tax			
	TAX ADJUSTMENTS			
9	Book Depreciation			
10	Tax Depreciation			
11	Charges to Construction			
12	Coal Depletion			
13	Other Adjustments			
	1.			
	2.			
	•			
	•			
	•			
14	Total Tax Adjustments			
15	Taxable Income			
16	Preferred Dividends Paid - Credit			
17	Total Taxable Income			
18	Gross Federal Income Tax			
19	Less Investment Credit			
20	Net Federal Income Tax			

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Appendix 1
Schedule 6H

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology

Other Included Items
Jurisdiction -

Line No.	Items/FERC Accounts (1)	Total Utility (2)	Allocation Basis 15a/ (3)	Jurisdictional Amount (4)
1	Operating Revenues:			
2	Nonfirm Sale for Resale/447			
3	1.			
4	2.			
5	3.			
6	Other Operating Revenues/450-456			
7	Acct. 450			
8	Acct. 451			
9	Acct. 452			
10	Acct. 453			
11	Acct. 454			
12	Acct. 455			
13	Acct. 456			
14	Total Revenues			
15	Other Items:			
16	Investment Tax Credit Adjustment/411.5			
17	Deferred Current Year			
18	Restored Current Year			
19	Restored from Prior Years			
20	Total ITC Adjustment			
21	Deferred Income Tax - Current/410.1			
22	Deferred Income Tax from prior years/411.1			
23	Other Accounts			

Average System Cost Methodology Footnotes

1/ Functionalized directly from the FERC Uniform System of Accounts.

2/ Unless it can be determined that a plant item or plant related item is associated directly with regional generation, transmission, distribution, customer or other directly functionalized category, the item shall be functionalized on the following basis in the following order:

(a) If the location codes of the plant item can be used to identify a principal generation, transmission, distribution or customer-related facility at that location, the plant item shall be functionalized based on the functionalization of such principal facility.

(b) For plant items not otherwise functionalized, the functionalization formula in footnote 24 shall apply.

3/ (a) The utility shall functionalize these items according to an analysis it performs that demonstrates the actual and/or intended functional use of the items, or the plant item related thereto, and include a detailed showing of the factors used to determine the functionalization as a supplement to Exhibit C, Appendix 1. Costs incurred only because the utility is engaged in the retail distribution of electricity shall be functionalized to Other. These items include, for example, retail revenue taxes and uncollectible amounts for retail sales.

(b) In cases where items included are not directly assigned to a particular function, these items shall be separately identified, and a statement shall be provided as to why the items are not directly functionalized by the 3(a) procedure. The functionalization formula described in footnote 24 herein shall apply to these items.

4/ Calculation of functionalized amount is to be consistent with property items included in functionalized Total Gross Plant.

5/ The offset against Contract System Costs for billing credit revenue arising from implementation of conservation measures and retail rate structures that induce conservation shall be limited to the costs included in Contract System Cost of the related conservation measures and retail rate structures. These billing credit revenues shall be functionalized on the same basis as the cost of the related conservation measure.

6/ Functionalization is to be directly related to the functional nature of the items included in the Working Capital calculation approved by the Commission. Should items included in the approved Working Capital calculation not be directly assignable to a function and should there be no footnote in this methodology directing the functionalization of the item, these items shall be separately identified and the functionalization formula in footnote 24 shall apply.

7/ Transmission plant means all land, conversion structures, and equipment employed at a primary source of supply (i.e., generating station or point of receipt in the case of purchased power) to change the voltage or frequency of electricity for the purpose of its more efficient or convenient transmission; all land, structures, lines, switching and conversion stations, high tension apparatus and their control in protection of equipment between a generating or receiving point and the entrance to a distribution center or wholesale point; and all lines and equipment whose primary purpose is to augment, integrate or tie together the sources of power supply. The entrance to a distribution center means all land, structures, conversion equipment, lines, line transformers and other facilities utilized to deliver power to specific customers or distribution substations.

8/ Distribution plant means all land, structures, conversion equipment, lines, line transformers, and other facilities employed between the primary source of supply (i.e, generating station, or point of receipt in the case of purchased power) and of delivery to customers, which are not includable in transmission system, as defined in footnote 7, whether or not such land, structures, and facilities are operated as part of a transmission system or as part of a distribution system.

Note: Stations that change electricity from transmission to distribution voltage shall be classified as distribution stations.

Where poles or towers support both transmission and distribution conductors, the poles, towers, anchors, guys, and rights-of-way shall be classified as transmission system. The conductors, crossarms, braces, grounds, tiewire, insulators, etc., shall be classified as transmission or distribution facilities, according to the purpose for which they are used.

Where underground conduit contains both transmission and distribution conductors, the underground conduit and right-of-way shall be classified as distribution facilities. The conductors shall be classified as transmission or distribution facilities according to the purpose for which they are used.

Land (other than rights-of-way) and structures used jointly for transmission and distribution purposes shall be classified as transmission or distribution according to their major use.

9/ Functionalized as specified in Schedule 4.

10/ If these items are treated in Schedule 1 as deductions from gross plant investment in determining rate base, these items shall not be included in the capital structure.

11/ Should a Commission approve a method for determining debt costs by a means other than that shown here, Schedule 2A shall be modified in a manner that shows the approved method, including accompanying explanatory material.

12/ Expenses related to the FERC Accounts 920-932 shall be functionalized in accord with the following:

FERC Account	Functionalization Method
920	Footnote 3
921	3
922	3
923	3
924	3(a) or 24(a)
925	3
926	13
927	19
928	19
929	3
930.1	19.
930.2	3
931	3
932	4

13/ Functionalization is to be determined on a pro rata percentage basis using the salary and wage data for production, transmission, and distribution/other functions included in the Test Period costs on which Appendix 1 is based. If, however, this information is unavailable, comparable data shall be used for the most recent calendar year as reported on the FERC Form 1 (at page 355), or similar document. Furthermore, a portion of this expense shall be included in Schedule 3, column 3, Excluded Amount, based on the amount of labor-related costs included therein.

14/ A tax-exempt Utility may include in-lieu taxes up to an amount that is comparable, for each unit of government paid in-lieu taxes, with taxes that would have been paid by a non-tax exempt Utility to that unit of government, but in no event shall the jurisdictional total in column 2 be greater than the actual amount paid.

15/ Excluded Resources

(a) The cost of additional resources in an amount sufficient to meet any additional load outside the region occurring after December 5, 1980, will be determined by utilizing allocation notes of multi-State utilities as assigned and utilized in State retail rate filings.

(b) The cost of additional resources sufficient to serve any New Large Single Load that was not contracted for, or committed to, prior to September 1, 1979, is to be determined as follows:

(1) To the extent that any New Large Single Loads are served by dedicated resources, at the cost of those resources, including applicable transmission;

(2) In the amount that New Large Single Loads are not served by dedicated resources, at Bonneville's New Resource rate as established from time to time pursuant to section 7(f) of the Regional Act and as applicable to the Utility, and applicable Bonneville transmission charges if transmission costs are excluded in the determination of Bonneville's New Resource rates, to the extent such costs are recovered by the Utility's retail rates in the applicable jurisdiction; and

(3) To the extent that New Large Single Loads are not served by dedicated resources plus the Utility's purchases at the New Resource rate, the costs of such excess load shall be determined by multiplying the kilowatthours not served under subsections (1) and (2) above by the cost (annual fixed plus variable cost, including an appropriate portion of general plant, administrative and general expense and other items not directly assignable) per kilowatthour of all baseload resources and long term power purchases (five years or more in duration), as allowed in the regulatory jurisdiction to establish retail rates during the Exchange Period, exclusive of the following resources and purchases: (a) purchases at the New Resources rate pursuant to section 7(f) of the Act; (b) purchases at the Federal Base System rate, pursuant to section 5(c) of the Act; (c) resources sold to Bonneville, pursuant to section 6(c)(1) of the Act; (d) dedicated resources specified in footnote 15(b)(1) of this agreement; (e) resources and purchases committed to the Utility's load as of September 1, 1979 under a power requirements contract or that would have been so committed had the Utility entered into such a contract; and (f) experimental or demonstration units or purchases therefrom. Transmission needed to carry power from such generation resources or power purchases shall be priced at the average cost of transmission for the Jurisdiction during the Exchange Period.

(4) Any kilowatthours of New Large Single Loads not met under subsections (1), (2), or (3) above will be assumed to be supplied from the most recently completed or acquired baseload resource(s) or long term power purchase(s), exclusive of dedicated resources and experimental or demonstration resources or purchases therefrom, that are committed to the Utility's load as of September 1, 1979, under a power requirements contract with Bonneville or would have been so committed had the Utility entered into such a power requirements contract. The cost of these generation resources and long-term power purchases and the transmission cost associated with these resources or purchases will be calculated as specified in subsection (3) above.

(5) If the New Large Single Load is served on an energy or capacity interruptible basis, the Utility shall prepare a calculation subject to review by Bonneville of the fixed (if any) and variable costs of providing such service, except that the amount excluded from ASC for the New large Single Load shall not be less than the transmission and generation costs included in the retail rate charged the New Large Single Load.

(c) Any costs associated with a generation facility that is terminated prior to initial commercial operation shall be excluded if termination occurred after December 5, 1980.

16/ Authorized Jurisdictional rate of return as specified in Schedule 2.

17/ The losses shall be the distribution energy losses occurring between the transmission portion of the Utility's system and the meters measuring firm energy load used by the Commission for the purpose of establishing retail rates. Losses shall be established according to a study (engineering, statistical or other) that is submitted to Bonneville by the exchanging Utility subject to review by Bonneville. This study shall be in sufficient detail so as to accurately identify average distribution losses associated with the Utility's total load, excluded loads, and the Residential load. Distribution losses shall include losses associated with distribution substations, primary distribution facilities, distribution transformers, secondary distribution facilities and service drops.

18/ This amount is to be reduced by revenues from firm sales for resale (to the extent that these sales are included in the Jurisdictional allocation factors) to be determined by the firm resale revenue for the Test Period as used for retail ratemaking purposes.

19/ Functionalize entirely to distribution/other unless Utility demonstrates that other functionalization treatment is appropriate.

20/ "Other" rate base items may include Unclassified Plant-In-Service (106), Extraordinary Property Losses (182), Other Investments (124), or other investments approved for rate base treatment by a Commission consistent with the provisions of this Exhibit.

21/ Only the conservation-related portion is to be functionalized to production.

22/ These revenues shall be divided proportionally between Excluded Amount and Total To Be Functionalized based on the total expenses in those two categories shown on Schedule 3 (sum of lines 1 to 13, 19, and 20), less all terminated plant expenses excluded pursuant to footnote 15(c). The portion to be functionalized shall be functionalized to production.

23/ Public Agencies shall be allowed a total return (operating income) on Schedule 1, line 26, column 2, equal to their demonstrated need for revenues exceeding Total Operating Expenses shown on Schedule 3 to cover the cost of capital. These demonstrated capital costs generally will be in the form of coverage requirements or the need to maintain an equity ratio consistent with favorable bond ratings for that Utility. In order to receive an operating income in addition to interest expense, the utility must submit evidence of the specific coverage or equity ratio needed by that utility and a calculation of the corresponding minimum operating income. Assignment to excluded resources and functionalization of the operating income shall be based on the assignment and functionalization of the rate base.

24/ Functionalization of these items shall be based on a formula that averages on an equal weighting basis the percentages for generation, transmission, distribution, and customer-related functions for (a) the gross plant in each function, including general plant and other plant items functionalized in step 1 of footnote 2 and, (b) the functionalized operations and maintenance (O&M) expenses shown in Schedule 3, except that the fuel cost included in O&M shall not include the cost of fuel acquired from non-Utility sources. Material detailing the application of this functionalization formula shall be included as a supplement to Appendix 1.

25/ Revenues from the transmission of electricity for others shall be functionalized to transmission.

[¶ 30,300]

46 F. R. 50539 (October 14, 1981)

18 CFR Part 282

[Docket No. RM81-28; Order No. 161]

Incremental Pricing; Elimination of 31 Metropolitan Regions

Issued: October 6, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is amending its regulations concerning incremental pricing under Title II of the Natural Gas Policy Act of 1978 (NGPA). The NGPA authorizes FERC to institute and administer an incremental pricing program to pass through, by surcharge, a portion of the increases in the wellhead prices of natural gas allowed under Title I of the Natural Gas Policy Act to certain industrial facilities that use natural gas as boiler fuel. This amendment removes the 31 metropolitan regions established by FERC in an effort to more accurately reflect the actual market prices which must be paid by these facilities. FERC is taking this action because of the difficulty the Energy Information Administration was experiencing in calculating statistically accurate price ceilings for the regions because of insufficient oil data.

DATE: Effective October 6, 1981.

FOR FURTHER INFORMATION CONTACT:

Thomas P. Gross, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8171, or

Sandra Delude, Federal Energy Regulatory Commission, 825 North Capitol Street N.E., Washington, D.C. 20426, (202) 357-5522.

SUPPLEMENTARY INFORMATION: The Federal Energy Regulatory Commission (Commission) is amending its regulations on incremental pricing (18 CFR Part 282) under Title II of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3301-3432). Specifically, § 282.404 is amended to eliminate the 31 metropolitan area incremental pricing regions.

I. Background

Title II of the NGPA requires the Commission, within certain guidelines, to institute and administer an incremental pricing program. The program is designed to pass through, by surcharge, a portion of the increases in the wellhead prices of natural gas allowed under Title I of the NGPA to certain industrial facilities that use natural gas as boiler fuel.

Generally, under Title II of the NGPA the incremental pricing surcharge applicable to a particular facility is the difference between the price that otherwise would have been paid for natural gas by that facility and the price at which the facility can purchase alternative fuel. The price of the alternative fuel (the alternative fuel price ceiling) is determined in accordance with section 204(e) of the NGPA.

Section 204(e) of the NGPA provides that the Commission is to designate the incremental pricing regions for which alternative fuel price ceilings are to be determined. In Order No. 50, 44 FR 57754 (October 5, 1979), the Commission established that there are 48 incremental pricing regions corresponding to the 48 contiguous states. It also provided that, as of October 20, 1980, the number of regions would be expanded to 79 regions, consisting of the 48 states and 31 metropolitan regions.

The Commission's purpose in establishing 31 metropolitan regions in addition to the 48 state regions was to accurately reflect actual market prices which must be paid by incrementally priced facilities located in large metropolitan areas. The Commission believed that, due to circumstances peculiar to large metropolitan areas, the price at which alternative fuel would be available to facilities located in those areas might differ significantly from the price at which the fuel would be available to facilities located in other areas in the state.

However, the Commission could not implement the metropolitan regions immediately, because the Energy Information Administration (EIA) was experiencing difficulties in calculating statistically accurate price ceilings for those regions due to insufficient oil price data.[1] The Commission therefore postponed implementation of the metropolitan regions until October 1980 to give the EIA time to develop a satisfactory methodology for making the necessary calculations. When it became clear that the EIA would not be able to meet the October 1980 date, the Commission postponed implementation of the metropolitan regions until October 20, 1981 (44 FR 5774 (October 5, 1979)).

In the meantime, the Commission explored the various difficulties associated with obtaining this data and sought comment in a related docket on the advisability, in light of these difficulties, of continuing its attempts to implement the metropolitan regions as incremental pricing regions. (*See*, Notice of Inquiry, Docket No. RM79-21, issued November 4, 1980, 45 FR 75405 (November 10,1980)). Although some comments urged implementation of the metropolitan regions based upon the different circumstances for facilities located in those regions as compared to facilities located elsewhere in the state, other commenters, including a large trade association representing the natural gas industry, urged the Commission to eliminate the metropolitan regions.

The trade association, previously an advocate of use of the metropolitan regions, reassessed its position and concluded that lack of available data on oil prices militates against adoption of the metropolitan areas.

On April 22, 1981, the Commission issued a Notice of Proposed Rulemaking (Notice) (46 FR 23950, April 29, 1981) in this docket, proposing to eliminate the 31 metropolitan regions altogether. The Commission received 11 written comments in response to this Notice. There were no requests for a public hearing.

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[1] The Energy Information Administration of the Department of Energy is responsible for the collection of data and the calculation and publication of the alternative fuel price ceilings.

II. Discussion

All but one comment [3] supported the proposed rule. Three comments suggested that a supplementary rule be implemented to accomodate special circumstances that the proposed rule would not cover. Specifically, the comments were concerned with a situation in which, either for geographic, transportation, or other reasons, the statewide price ceiling does not fairly reflect the local competitive situation and consequently major load loss may be threatened. One of the commenters cites, as examples, three metropolitan regions—Buffalo, Pittsburgh, and Cleveland—where prices may differ materially from the average price for the state as a whole. These commenters therefore suggest that the Commission use the metropolitan regions in those special situations where significant disparities in fuel price ceilings occur within a state or in contiguous states.

After carefully considering the suggestion for a supplementary rule, the Commission declines to adopt it. The Commission observes that the NGPA itself provides a mechanism to deal with the special circumstances to which the comments refer. Section 502(c) of the NGPA is specifically designed to alleviate situations of special hardship, inequity, or unfair distribution of burdens. In fact, one company, Berkshire Gas Company, has filed an application under section 502(c) (Docket No. SA81-53-000) to obtain the very type of relief that the comments have proposed. The Commission believes that, if a disparity in the alternative fuel price ceilings occurs that may result in special hardship, inequity, or an unfair distribution of burdens, section 502(c) of the NGPA is available to any person. The Commission therefore concludes that no need exists for a supplementary provision as suggested by the above comments.

After more than a year of experience in administering the program with 48 incremental pricing regions, and more than two years effort in studying the advantages and disadvantages associated with implementation of the 31 metropolitan regions, the Commission believes that no benefit will be gained by adding the 31 metropolitan areas as incremental pricing regions. The lack of statistically significant data upon which to base calculations of alternative fuel price ceilings for the metropolitan regions makes the purpose for adding the regions (more accurate price ceilings) unattainable. Accordingly, the Commission is eliminating the 31 metropolitan regions, and retaining the 48 state regions, as incremental pricing regions.

III. Summary of the Rule

This rule amends § 282.404 and Appendix I to Subpart D of Part 282 of the Commission's regulations. Paragraph (a) of § 282.404, which sets forth the general rule for publishing alternative fuel price ceilings and lists corrections to previously published price ceilings, is not changed by this rule.

Paragraph (b)(1) of § 282.404, which establishes the date upon which the monthly price ceilings will be published, remains unchanged in substance by this rule. Paragraph (b)(2), which established the date for publication of price ceilings for the metropolitan regions, is deleted.

Prior to issuance of this rule, paragraph (c)(1) of § 282.404 provided that, until publication of price ceilings for the metropolitan regions, the 48 state regions are the incremental pricing regions. This rule deletes the clause referring to the metropolitan regions, thus removing the metropolitan region limitation on the 48 state regions as incremental pricing regions. Paragraph (c)(2) which provided that, after the date of publication of price ceilings for the metropolitan regions, the incremental pricing regions will be the 48 state regions and the 31 metropolitan regions, is deleted.

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[3] That commenter did not address itself to the issue of the proposed rule, but merely reiterated its interest in the so-called "contiguous state approach" which the Commission has already considered in Docket No. RM79-21.

Appendix I to Subpart D of Part 282 listed the 31 metropolitan regions and eight multistate regions. This rule deletes the list of metropolitan regions.

Finally, the map at the end of Appendix I, on which the metropolitan regions were represented, is deleted by this rule.

IV. Effective Date

In Order Nos. 50 and 81, the Commission temporarily deferred implementation of the metropolitan regions and used the 48 contiguous states as incremental pricing regions. This rule maintains the status quo established by Order Nos. 50 and 81 by continuing to use the 48 contiguous states as incremental pricing regions and eliminating the 31 metropolitan regions. Moreover, to implement the metropolitan region alternative fuel price ceilings for 30 days would be very disruptive and costly, and would serve no useful purpose. Accordingly, in accordance with 5 U.S.C. 553(d), the Commission finds that good cause exists to make this rule effective upon issuance.

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301 *et seq.*, Department of Energy Organization Act, 42 U.S.C. 7701 *et seq.*, E.O. 12009, 42 CFR 46267 (1978))

In consideration of the foregoing, the Commission amends Part 282, Subchapter I of Chapter I, Title 18 of the Code of Federal Regulations, as provided below, effective upon issuance.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,301]

46 F. R. 50785 (October 15, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Texas—9 Addition); Order 180]

High-Cost Gas Produced From Tight Formations; Final Rule

October 8, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Railroad Commission of Texas that an additional area of the Travis Peak Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: October 8, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Walter Lawson, (202) 357-8556.

SUPPLEMENTARY INFORMATION:

The Commission hereby amends § 271.703(d) of its regulations to include an additional area of the Travis Peak Formation in Texas as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by the Director, OPPR, issued July 24, 1981 (46 FR 38935, July 30, 1981)[1] based on a recommendation by the Railroad Commission of Texas (Texas) in accordance with § 271.703(c) that an additional area of the Travis Peak be designated as a tight formation.

Evidence submitted by Texas supports the assertion that the Travis Peak Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Texas recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and, therefore, incentive prices should be made available as soon as possible.

The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3342; Administrative Procedure Act, 5 U.S.C. 553)

For the reasons stated herein, Part 271 of Subchapter H, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective October 8, 1981.

By the Commission.
Kenneth F. Plumb,
Secretary.

[¶ 30,302]

46 F. R. 51381 (October 20, 1981)

18 CFR Part 270

[Docket No. RM80-33]

Standard for Determining the Btu Content of Natural Gas

Issued: October 8, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of effective date.

SUMMARY: On August 20, 1981, the Federal Energy Regulatory Commission issued an order granting partial stay of Order Nos. 93 and 93–A, relating to the standard of determining the Btu content of natural gas pending further order, 46 FR 45599 (September 14, 1981), subject to the approval of the United States Court of Appeals for the District of Columbia Circuit. On September 17, 1981, the court remanded the record, thereby approving the order. The order granting partial stay of Order Nos. 93 and 93–A pending further order thus became effective as of August 20, 1981.

EFFECTIVE DATE: August 20, 1981.

FOR FURTHER INFORMATION CONTACT: Teresa Ponder, Deputy Assistant General Counsel, Rulemaking and Legislative Analysis, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (357–8151).

SUPPLEMENTARY INFORMATION: On July 16, 1980, the Commission issued Order No. 93, Docket No. RM80–33; 45 FR 49077; (July 23, 1980) amending and issuing as final rules the regulation in 18 CFR 270.204 relating to the standard for determining the Btu content of natural gas. On April 24, 1981, the Commission issued Order No. 93–A, entitled "Order Denying Rehearing and Clarifying Order No. 93" (46 FR 24537; May 1, 1981).

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[1] Comments were invited and one comment supporting the recommendation was received. No party requested a public hearing and no hearing was held.

The order issued August 20, 1981, stayed Order Nos. 93 and 93–A, pending further order, insofar as they concluded that the standard they prescribed for determining Btu content of natural gas was in effect from December 1, 1978, to April 24, 1981 (the date Order No. 93–A was issued). The order issued August 20 was subject to the approval of the United States Court of Appeals for the District of Columbia Circuit.

On September 17, 1980, the Court granted the Commission's motion to remand the record to the Commission. Thus, the order issued on August 20, 1981, granting partial stay of Order Nos. 93 and 93–A, pending further order became effective August 20, 1981.

Kenneth F. Plumb,

Secretary.

[¶ 30,303]

46 F. R. 53651 (October 30, 1981)

18 CFR Part 2

[Order No. 2–A; Docket No. RM75–25]

Natural Gas; Policy Statement on Certification of Pipeline Transportation Agreements

Issued: June 23, 1978. [1]

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Order clarifying policy statement.

SUMMARY: In this order, the Commission addressed applications for reconsideration of its Order No. 2 (43 FR 5362, February 8, 1978). That order modified a statement of policy with respect to the transportation by jurisdictional pipelines of natural gas sold by certain producers from the onshore and the off-shore non-federal domain to non-resale industrial and commercial customers for high priority uses. In addition to discussing certain clarifications of policy, the Commission revised a filing requirement to require submission of only available data on whether gas has been previously sold from the acreage involved.

EFFECTIVE DATE: June 23, 1978.

FOR FURTHER INFORMATION CONTACT: Kenneth F. Plumb, Secretary, Federal Energy Regulatory Commission, 825 North Capitol St., N.E., Washington, D.C. 20426 (202) 357–8400.

SUPPLEMENTARY INFORMATION:

Order Granting in Part and Denying in Part Reconsideration and Clarifying Order No. 2

On February 1, 1978, the Commission issued Order No. 2, which modified § 2.79 of the Commission's General Policy and Interpretations, a statement of policy with respect to the transportation by jurisdictional pipelines of natural gas sold by certain producers from the on-shore and the off-shore non-federal domain to non-resale industrial and commercial customers for high priority uses. Applications for rehearing [1a] and clarification of this order were filed on March 3, 1978 by Aluminum Company of America (Alcoa), the Industrial Users (IU),[2] and Tennessee Gas Pipeline Company, a Division of Tenneco (Tennessee). These applications for reconsideration were granted for the purpose of further consideration by order issued March 28, 1978.

None of the petitions challenge the legality of the Commission's action. Subsequent to the issuance of Order No. 2, the United States Court of Appeals for the District of Columbia Circuit [8] sustained the legality of the policy statement, initially set forth in Order Nos. 533 and 533–A, concluding:

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[1] Through administrative error, this order had not been published in the Federal Register.

[1a] Although applications for rehearing are not proper due to the nature of this Order No. 2, the Commission will treat such filings as applications for reconsideration for purposes of this order.

[2] General Electric Company, Glass Containers Corporation, Lithium Corporation of America, Owens Illinois, Inc., and Reynolds Metals Company jointly applied for rehearing as the Industrial Users.

> We approve the Commission's plan embodied in Order No. 533 as a legitimate, experimental approach for dealing with the inherently skewed nature of our half-free market. The diversion of on-shore gas to the unregulated sector is inevitable in the absence of strong counter measures, and the Commission must have leeway to experiment (footnote omitted) in devising the optimal remedy. This approval is as to the general policy, as an experimental effort. Interested parties will, of course, have an opportunity to contest application of the plan to particular facts.

Order No. 2 continues the 533 program; however, the Commission has established stricter reporting requirements to more closely monitor its operation.

In its petition, Alcoa argues that the scope of Order No. 2 should be expanded to incorporate many of the proposals it submitted in its comments filed in response to the notice of intent to review the policy statement of Order Nos. 533 and 533–A. Many of these proposals were addressed in detail in Order No. 2 and in its petition for reconsideration, Alcoa does not advance arguments based upon new facts or law to sustain its position.

Alcoa and IU both assert that existing customers should be permitted to receive certification under Order No. 2 for the expanded needs of existing facilities. In its June, 1977 notice, the FPC stated its intent to review the eligibility criteria established by Order Nos. 533 and 533–A which limited the application of the policy to existing customers of interstate pipelines who were subject to curtailment. The Commission proposed the following three categories of service for possible inclusion: (1) The transportation of direct sale gas to new customers, (2) customers not served by the interstate pipeline and/or (3) volumes in excess of those presently being received by existing customers through jurisdictional pipeline suppliers. In Order No. 2, the Commission concluded that this policy aspect should not be modified and specifically found that certification of the transportation of 533 gas should not be granted for the three proposed categories of service.

The Commission foresaw that the transportation of 533 supplies to a new facility could result in dependence upon short-term supplies, thereby discouraging the initial use of an alternate fuel source and requiring costly conversion of plant facilities after a relatively short period of plant operation. The Commission applied the same rationale in its review of the third proposed category based upon its assumption that any need for additional volumes by a gas customer currently receiving 533 supplies probably would be due to an expansion of industrial production and operation which might better be accomplished by the use of alternative fuels.

We reaffirm our findings that an industrial who is an existing customer of an interstate pipeline may not receive 533 volumes to offset curtailment of its pipeline entitlement when such volumes will be used for plant expansion of either its operation or production. Although existing customers may receive 533 volumes which do not exceed contract demand if these supplies will be used for feedstock, plant protection or process uses, these supplies may not be used for new high priority requirements. The proposed modifications to the policy statement would create an obvious inconsistency in our determination that new customers are ineligible to participate in these transactions. An inconsistency in treatment could be viewed as discriminatory as existing facilities would be allowed to grow using these supplies whereas a new operation would be precluded from using an energy supply which may be cheaper than alternate fuel.

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[8] American Public Gas Association and Consumers Federation of America v. Federal Energy Regulatory Commission, D.C. Cir. No. 75-2105, decided May 10, 1978.

Moreover, the purpose of this policy is to provide short-term relief to industrial customers who presently need natural gas to offset curtailment and thereby *maintain* their current level of operations. The term of this relief not only presumes, but encourages, the industrial customers to install alternate fuel facilities or develop such for those uses which have been classified as high priority. As the supply of natural gas dwindles, the need for conversion measures is accelerating. Interim relief as provided in Order No. 2 cannot be the long-term solution for these facilities, but only a means of ameliorating the adverse effects on production and employment which result from curtailment.

In relation to the foregoing Alcoa cites the following statement in Order No. 2 [4] and requests that the Commission "withhold any final determination concerning such transportation * * * until a final determination concerning such matters is reached in Docket Nos. CP77-71, CP77-118, and CP77-125 * * *."

> Applications for transportation of consumer-owned gas or reserves in place made pursuant to § 2.79 for a period not exceeding two years may be construed as falling within the scope of the policy.

Applicants may seek Commission authorization for transportation of gas supplies under Section 7(c) of the Natural Gas Act which the Commission shall review on a case-by-case basis. As provided in Order No. 2, the transportation of consumer-owned gas or reserves in place for periods exceeding two years does not fall within the scope of the policy statement.[5] However, our consideration of applications for the transportation of such gas for periods not exceeding two years will not be delayed pending the final determination in the on-going administrative proceeding.

Alcoa and IU maintain the Commission should ease the end-use restrictions provided in Order No. 2 during summer or off-peak seasonal periods. Alcoa suggests that industrial consumers should be allowed to take full pipeline entitlement in addition to minimum volumes of 533 supply. IU proposes that the policy should be modified to permit an industrial consumer to receive his proportionate share of gas available for low priorities reduced by the volumes of 533 supplies being received. Both petitioners assert that the Commission's application of the eligibility criteria to actual operations operates as a penalty against those who engage in self-help efforts.

In Order No. 2, the Commission recognized that the take-or-pay provisions in underlying producer contracts and the end use limitations of the policy could result in the loss of 533 supplies purchased but not yet delivered. The Commission rejected proposals similar to those advanced by Alcoa and IU, concluding that the end use restrictions it had placed on 533 supplies should be maintained in order to insure that industrial customers used the supplies solely for high-priority uses. In order to provide the industrial customer with some flexibility to cope with this potential inequity, we provided for the grant of a six-month extension of the term for receipt of these volumes upon compliance with certain reporting requirements.

After thorough reconsideration, we find that, to maintain the integrity of this policy statement, our initial findings should not be modified. During this period of worsening natural gas shortage, we are reluctant to establish more lax criteria which could potentially result in a larger available supply for low priority uses. As previously stated, we view the policy statement of Order

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[4] Errata Notice issued February 10, 1978.

[5] This question is presently the subject of an administrative proceeding entitled Natural Gas Pipeline Company of America, Docket No. CP77-71, *et al.* Orders issued February 21, 1978 and May 12, 1978.

No. 2 as a means of enabling industrial consumers to receive short-term supplies of natural gas essential for their operations pending the development and/or installation of alternate fuel capability. Our modification of the policy providing six-month extensions to the two-year term appears to allow the producer and industrial customers sufficient flexibility to reduce the potential for economic hardships upon the industrial, however, should future transactions indicate that it is not, we shall undertake a review of this issue.

IU requested clarification of the six-month extension provision. In Order No. 2, the Commission concluded that an underlying producer's contract containing a take-or-pay provision must include an opportunity for the industrial consumer to make up gas it could be unable to take during the principal term of the certificate. Although IU supports this policy modification, it argues that it is inappropriate for the Commission to require the inclusion of this provision in sales contracts executed with non-jurisdictional producers.

As expressed in Order No. 2, we believe that the opportunity for rextension of a 533 sales contract is an essential means of offsetting some of the economic inequities which may result from a take-or-pay provision which is characteristic of 533 sales contracts. In considering whether a proposed 533 transaction should be certificated, the provision of a six-month extension period will be a significant element in our determination whether the overall proposed transportation of these interruptible supplies for high priority uses is in the public convenience and necessity. The presence of a six-month extension period in a contract with a take-or-pay provision assists the Commission's review of the proposed price of the supplies as it reduces the possibility that the cost of the supplies may be inflated. A sales agreement between the producer and industrial which does not make provision for a six-month extension after the expiration of the contract term will be viewed by the Commission as creating a significant condition for the proposed transaction to operate outside the intent of our policy statement. We would view the omission of such a six-month provision from any such contract as an obstacle to this Commission finding that the overall contract is in the public interest. While we do not require such inclusion, we strongly encourage the incorporation of such provisions.

Alcoa requests clarification as to the Commission's intent of requiring the filing of information related to the costs paid by an industrial customer for gathering facilities. As expressed in Order No. 2, the Commission has established certain filing requirements in order to assist its review of proposed transactions in which the industrial customer assumes the economic burden of installing gathering facilities; however, the producer retains the title. The submission of this data will assist our review as to whether there is a potential for the industrial to pay a fee which exceeds the actual cost of the facilities necessary to implement the proposed transactions. In order to make the requisite statutory finding that the proposed transportation of these supplies is in the public convenience and necessity, it is essential to review all aspects of the proposal.

Both Tennessee and IU request clarification as to certain reporting requirements. As set forth in its petition, Tennessee has correctly interpreted the intent of Order No. 2 that only the interstate pipeline delivering volumes to the distributor for delivery to the industrial consumer need file a monthly report reflecting those volumes it received and transported. Based upon the elimination of the filing requirements for transporting pipelines other than delivering pipelines in Order No. 2, we find it necessary to further modify the Order to eliminate the same filing requirements for all 533 transactions certificated prior to its issuance as the information is not essential to our monitoring the program.

IU requests that the Commission delete the filing requirements set forth in § 2.79(g)(2)(vii) through (xi) or, in the alternative, the information required in

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paragraphs (g)(2) (ix) and (x) should be limited to circumstances when the data is available. Upon review, we find that paragraph (g)(2) (x) should be modified to require the submission of only available data; however, a good faith effort should be made to obtain such information. The remaining filing requirements are reasonable on their face and consistent with this Commission's intent to closely monitor the operation and effects of the policy.

With the exception of the modification set forth above, we find that petitioners' applications for reconsideration present no new facts or principles of law which warrant any modifications of Order No. 2.

The Commission orders:

(A) The petitions for reconsideration and clarification filed on March 3, 1978 by Aluminum Company of America, the Industrial Users and Tennessee Pipeline, a Division of Tenneco, Inc. are denied other than as herein provided.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,304]

46 F. R. 53653 (October 30, 1981)

18 CFR Part 271

[Docket No. RM80-53]

Prescribed Maximum Lawful Prices Prescribed Under Title I of the Natural Gas Policy Act

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Order of the Director, OPPR.

SUMMARY: Pursuant to the authority delegated by 18 CFR 357.307(1), the Director of the Office of Pipeline and Producer Regulation revises and publishes the maximum lawful prices prescribed under Title I of the Natural Gas Policy Act (NGPA) for the months of November, and December, 1981 and January, 1982. Section 101(b)(6) of the NGPA requires that the Commission compute and publish the maximum lawful prices before the beginning of each month for which the figures apply.

EFFECTIVE DATE: November 1, 1981.

FOR FURTHER INFORMATION CONTACT: Kenneth A. Williams, Director, OPPR (202) 357-8500.

SUPPLMENTARY INFORMATION:

Issued: October 22, 1981.

Section 101(b)(6) of the Natural Gas Policy Act of 1978 (NGPA) requires that the Commission compute and make available maximum lawful prices and inflation adjustments prescribed in Title I of the NGPA before the beginning of any month for which such figures apply.

Pursuant to this requirement and § 375.307(1) of the Commission's regulations, which delegates the publication of such prices and inflation adjustments to the Director of the Office of Pipeline and Producer Regulation, the maximum lawful prices for the months of November and December, 1981 and January, 1982 are issued by the publication of the price tables for the applicable quarter. Pricing tables are found in § 271.101(a) of the Commission's regulations. Table I of § 271.101(a) specifies the maximum lawful prices for gas subject to sections 102, 103, 106(b)(1)(B), 107(c)(5), 108, and 109 of the NGPA. Table II of § 271.101(a) specifies the maximum lawful prices for sections 104 and 106(a) of the NGPA. Table III of § 271.102(c) contains the inflation adjustment factors.

Kenneth A. Williams,
Director, Office of Pipeline and Producer Regulation.

[¶ 30,305]

46 F. R. 55245 (November 9, 1981)

18 CFR Parts 1 and 4

[Docket No. RM81-15; Order No. 183]

Revisions to Certain Regulations Governing Applications for Preliminary

Permit and License for Water Power Projects

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) amends its regulations governing preliminary permit and license applications for water power projects, to: (1) Grant automatically most petitions to intervene in preliminary permit proceedings; (2) eliminate notices of intent to file preliminary permit applications for projects at existing dams; (3) amend the standard for evaluating certain competing applications to conform more closely to the statute; (4) require from municipal applicants evidence of competency under state law; (5) provide for changes in filing dates for applications amended after filing; and (6) clarify Commission policy regarding holders of any proprietary interest in a project.

The revisions are designed to aid the expeditious development of water power projects by eliminating unnecessary procedures, clarifying existing policy, requiring certain necessary information in applications, and correcting the standard for evaluating certain competing applications. The rule would affect existing §§ 1.8, 4.30, 4.33, 4.51, and 4.81 and create a new § 4.35.

DATE: This rule is effective October 29, 1981.

FOR FURTHER INFORMATION CONTACT:

James Hoecker, Division of Rulemaking and Legislative Analysis, Office of the General Counsel, Federal Energy Regulatory Commission, Washington, D.C. 20426, (202) 357-8342

Ronald Corso, Director, Division of Hydropower Licensing, Office of Electric Power Regulation, Federal Energy Regulatory Commission, Washington, D.C. 20426, (202) 376-9171

SUPPLEMENTARY INFORMATION:

Issued October 29, 1981.

The Federal Energy Regulatory Commission (Commission) amends certain provisions in its regulations governing preliminary permit and license applications for water power projects. The revisions are designed to aid the expeditious development of water power projects by eliminating unnecessary procedures, requiring certain necessary information in applications, and correcting the standard for evaluating certain competing applications. The final rule affects existing §§ 1.8, 4.30, 4.33, 4.51, and 4.81 and creates a new § 4.35.

I. Background

Over the past three years, the Commission has carried forward a program of licensing reform for water power projects, including revision of the regulations governing preliminary permit applications and various kinds of license applications.[1] The revised regulations have helped to reduce the time which must be devoted to preparing an application and have enabled the Commission to process applications more quickly than before. For example, it now takes 3 to 4 months to process an application for a preliminary permit, instead of the previous average time of 24 months.

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[1] Order No. 11, "Simplified Procedures For Certain Water Power Licenses" (Docket No. RM78-9), issued September 5, 1978, 43 FR 40215, September 11, 1978.

Order No. 54, "Regulations Prescribing General Provisions for Preliminary Permit and License Applications; and Regulations Governing applications for Amendments to and Cancellation of Preliminary Permits" (Docket No. RM79-23), issued October 22, 1979, 44 FR 61328, October 25, 1979.

Order No. 59, "Regulations Governing Applications for License for Major Projects—Existing Dam" (Docket No. RM79-36) issued December 18, 1979, 45 FR 75383, December 28, 1979.

Order No. 106, "Exemption from All or Part of Part I of the Federal Power Act of Small Hydroelectric Power Projects With an Installed Capacity of 5 Megawatts or Less," (Docket No. RM80-05), issued November 7, 1980, 45 FR 76115, November 18, 1980.

Order No. 123, "Procedural and Correctional Revisions to Regulations Governing Preliminary Permits and Licenses," (Docket No. RM81-11), issued January 21, 1981, 46 FR 9027, January 28, 1981.

Notice of Proposed Rulemaking, "Regulations Governing Applications for Minor Water Power Projects and Major Water Power Projects 5 Megawatts or Less" (Docket No. RM81-10), issued January 21, 1981, 46 FR [illegible], January 29, 1981.

Notice of Proposed Rulemaking, "Regulations Governing Application for License for Major Unconstructed and Major Modified Projects; Applications for License for Transmission Line Only; Applications for Amendment to License" (Docket No. RM80-39), issued January 23, 1981, 46 FR 10165, February 2, 1981.

Despite this progress, the renewed interest in hydropower development—inspired in part by the Commission's small power production and cogeneration rulemakings [2] and its current program to exempt certain projects from all or part of Part I of the Federal Power Act [3]—has increased the Commission's workload dramatically. This is readily ascertained by examining the number of preliminary permit applications received over the last four years. The Commission received 18 preliminary permit applications in 1977, 36 in 1978, and 76 in 1979; however, in 1980, the Commission received 501 such applications. At least 1,800 applications are anticipated during FY 1981.

The rulemaking of Docket No. RM81-15 is designed to expedite further the licensing of water power projects by clarifying and streamlining some Commission procedures to deal with the following situations:

1. *Interventions.* Interventions in proceedings initiated by the filing of a preliminary permit application are proposed to be granted automatically, with some exceptions, both because the multiple interventions in such proceedings are largely to obtain service of papers and to protect the potential interests of certain parties, including state commissions, and because the permits themselves normally do not entail substantial environmental consequences that would be a basis for genuine opposition to granting the application. The final rule obviates issuance of routine orders to grant intervention.

2. *Notices of intent.* The filing of a notice of intent to file a competing preliminary permit application has frequently and unnecessarily extended (2 to 3 months) the notice period required for applications and thereby delayed Commission action. The owner of a potential site for which a non-owner has filed a permit application would be sufficiently shielded from surprise even without this device, because notice of the application will always be mailed by the Commission directly to that person.

3. *Competency under state law.* Under section 3(7) of the Federal Power Act, a "municipality" must be "competent under the laws [of the state] thereof to carry on the business of developing, transmitting, utilizing, or distributing power." This qualification is particularly important for administration of the state/municipal preference under section 7(a) of the Act. Without evidence of this competency in the permit or license application, the Commission may have to request such information by separate letter in order to prevent granting a preference to the inappropriate person.

4. *Amendments to file applications.* Applications for a preliminary permit or a license are amended by applicants, sometimes drastically, after acceptance for filing in a manner that changes the status of the filing party (*e.g.*, from "citizen" to "municipality") or the fundamental plan of development. Under existing practice, upgrading a plan of development—even if such improvements are derived from the plans of a subsequently filed application—does not affect the priority in time of the amended application. For purposes of establishing a priority of filings, fairness dictates that fundamental changes be regarded as the filing of a new application.

5. *Financial capability.* Section 7(a) of the Act requires that, where at least one

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[2] Order No. 69, "Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978" (Docket No. RM79-55), issued February 19, 1980, 45 FR 12214, February 25, 1980; Order No. 70, "Small Power Production and Cogeneration Facilities—Qualifying Status" (Docket No. RM79-54), issued March 13, 1980, 45 FR 17959, March 20, 1980.

[3] Order No. 106, *supra.*

competing preliminary permit or license applicant is a state or municipality and another is not, public entities are preferred to non-public applicants if the plans of each are "equally well adapted to conserve and utilize in the public interest the water resources of the region." The ability of the parties to carry out the plans is not a test which the Act expressly applies to such applications, unless all or none of the competing applicants is a public entity. The final rule conforms the Commission's regulations to section 7(a). Nevertheless, the financial capability of any applicant may be an important factor in the Commission's decision to issue a license based on the best adapted plan.

6. *Identity of applicants.* The advent of new financial arrangements which enable a prospective licensee to engage in hydropower development with support from other parties or institutions poses serious questions about the identity of a permit or license applicant. This has potential significance for the filing priorities of applicants and the Commission's ability to regulate a licensed project through the licensee.

The Commission has emphasized in recent orders the traditional requirement that, for purposes of assigning the public preference under section 7(a) of the Act and carrying out, through the permittee or licensee, the regulatory responsiblities mandated by the Act, anyone intending to be a licencee must have or acquire all rights necessary for the construction, operation and maintenance of the project.[4] In light of this policy, § 4.30(d) is added to remind applicants that any person possessing or intending to acquire such proprietary interests and to maintain them when the proposed project is operational should be a coapplicant for a permit or a license. When, at the licensing stage, the Commission accounts for all interests in a project, the license applicant(s) must be determined to control all the interests essential to managing the development. If other persons in fact have or share those interests, the applicant risks loss of whatever priorities it may have established. This longstanding policy is expressed in an amendment to § 4.30 in the final rule, although the language was not originally included in the rule as proposed.

II. Comment Summary

Twenty-eight comments were submitted pursuant to the Notice of Proposed Rulemaking, issued February 26, 1981 (46 FR 14751, March 2, 1981), in this docket. Generally, the commenters raise issues that reflect the competing considerations of affording widespread opportunity to participate in Commission proceedings and to compete for Commission authorization to develop and operate hydroelectric power projects versus the need to expedite approval and development of such projects.

A. Automatic Intervention Under § 4.31(h)

The proposed rule established a procedure for automatic intervention in preliminary permit proceedings when the intervention sought is unopposed by initial and competing applicants in the proceeding and the Commission does not deny or stay intervention within 15 days of the close of the period for requesting intervention. Four of the commenters endorsed the proposal, stating, among other things, that an automatic procedure would free the Commission staff to consider more important tasks. Three commenters opposed the procedure. Two of the commenters opposing the proposal expressed concern that proceedings would be enlarged and complicated by the presence of more intervenors and non-meritorious competing applications.

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[4] City of Fayetteville Public Works Commission, *et. al.*, Project Nos. 3137 and 3086, "Order Determining Preferences, Issuing Preliminary Permit and Denying Competing Application", issued September 16, 1981; New York State Electric and Gas Corporation, Project No. 2934, "Order Denying Appeal", issued September 16, 1981; Niagara Mohawk Power Corporation, Project No. 3452, "Order Denying Appeal", issued September 11, 1981. See Standard Article 5, Forms L-1 through L-21 (revised October 1975).

The Commission received no convincing evidence that an automatic intervention process will encourage an unmanageable number of entities to intervene or file competing applications in preliminary permit proceedings. Further, the Commission has retained the ability of a permit applicant to oppose intervention under the standards and procedures § 1.8 of its regulations, so that participation may still be evaluated and limited, if necessary. The Commission's rules permit certain limitations to be placed upon participation by interveners with substantially similar interests and positions. The Commission is therefore persuaded that automatic intervention will not lead to enlarged and complicated proceedings.

Another commenter argues for a different approach; it urges the Commission to permit intervention only by competing applicants, relegating the participation of other interested persons to the submission of protests. While this suggestion goes beyond the scope of the purely procedural proposal in this docket, the Commission feels that such a restriction on participation of persons other than competing applicants would contradict the Commission's responsibility to inquire into the interests sought to be protected by other persons.[5] Therefore, the Commission retains its original proposal, permitting the Commission to grant automatically any unopposed petition to intervene in a permitting proceeding instead of issuing a large number of *pro forma* orders granting intervention.[6]

B. Elimination of Notices of Intent To Submit an Application for a Preliminary Permit for Proposed Major Projects—Existing Dam Under § 4.50(b)(5) and Certain Proposed Minor Water Power Projects Under § 4.60(b)(4)

The Commission proposed elimination of notices of intent to file preliminary permit applications for major projects—existing dam and projects with a capacity of 1.5 MW or less (minor) which utilize an existing dam. The proposed rule would have required a prospective competing applicant to file its completed permit application within the period provided for interested persons to file protests and petitions to intervene, usually 60 days after publication of notice of the application.

Municipalities oppose this proposal, stating that state and municipal decisionmakers require greater time to determine whether to file a competing permit application. One commenter argues that a state-wide association of municipalities may not receive actual notice in time to formulate a competing proposal, because the Commission sends notice only to those municipalities that are likely to be interested in the application. Commenters state that elimination of the notice of intent in these permit proceedings does not give a municipality sufficient time to investigate properly the possibility of developing a dam site, to perform legal and engineering analysis, and to compete effectively to develop the site. They claim that this result contradicts the statutory scheme of preference for public development. Public entities would, it is argued, protect themselves by submitting a competing application before adequate investigation of the potential power site, thereby increasing the number of contested applications and the Commission's workload. Opponents of the proposal also maintain that financial costs to municipalities would increase because an "equally well adapted plan" would have to be submitted after the initial application. These commenters suggest that allowing more time for municipalities to negotiate arrangements with prospective applicants would promote settlements, avoid costly administrative procedures, and bring projects "on line" sooner.

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[5] *See, Scenic Hudson Preservation Conference* v. *FPC*, 354 F.2d 608 (2d Cir. 1965), *cert. denied* 384 U.S. 941 (1966), and *Office of Communication of the United Church of Christ* v. *FCC*, 359 F.2d 994 (D.C. Cir. 1966).

[6] The Commission has proposed revisions in its general intervention rules in Docket No. RM78-22 (Part 7), 46 FR 17023 (March 17, 1981). The proposed rule would grant automatic intervention to those requesting intervention, as well as inclusion on relevant service lists and permission to make motions, unless the Commission denies the petition to intervene.

Some utilities express a belief that elimination of the notice of intent would lead to increased plagiarism from initial applications. On the other hand, other utilities support the proposed rule as an effort to streamline Commission procedures.

The Commission believes that elimination of notices of intent to file applications for preliminary permits can significantly reduce delays in reviewing permit applications and shorten contested permit proceedings by 60 days or more. Notices of intent may be submitted by persons who lack a bona fide intent to develop a project as a device to foil development by other persons. Such practices should be discouraged. Sufficient opportunity to halt or change a proposed project exists within existing procedural safeguards such as protest, intervention, and actual notice to potentially interested municipalities. Therefore, the Commission is eliminating the notice of intent procedure for two classes of projects.

The Commission nevertheless appreciates the concerns which several commenters express with respect to the time necessary to develop competing applications, a process substantially more complex than preparing notices of intent. In particular, the Commission recognizes the special procedures associated with decisionmaking in local governmental institutions. States and municipalities which only react to the proposals of other potential developers are at a disadvantage if local law requires a referendum or other formal consideration of the project. Therefore, the Commission has decided to permit, in all cases, an additional 30 days after the close of the intervention and protest period for the filing of competing applications for preliminary permits for major projects—existing dam and those minor water power projects which utilize an existing dam. The notice of intent mechanism is retained for all other kinds of hydroelectric power projects.

C. Standards for Preliminary Permits and Licenses When One Applicant Is a Public Entity

The proposed rule contemplated revision of the regulation under which preliminary permits and licenses are awarded when one applicant is a public entity and the other applicant is a private entity, by deleting the phrase "taking into consideration the ability for each applicant to carry out its plan" (§ 4.33 (g)(3) and (g)(4)).

Municipalities uniformly support this proposal on the basis that it favors the interest of municipal development of hydroelectric projects under section 7(a) of the Federal Power Act. Private industry commenters opposed the revision, claiming that it would enable a municipality to receive a permit or a license even though it was financially unable to develop the project in queston.

The Commission merely proposed revision of § 4.33 to comport with express statutory language.[7] When one applicant is a public entity and competing applicants are not, the Commission must give a preference to the state or municipality if the plants are equally well adapted (or may be made so within a reasonable time) to conserve and utilize in the public interest the water resources of the region. When all or none of the applicants is a public entity, the Commission is required to ascertain whether the applicant is able to carry out its plans. As proposed, the revision merely conforms the Commission's regulation to the statute. The revision is therefore adopted as proposed.

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[7] Sec. 7(a). In issuing preliminary permits hereunder or licenses where no preliminary permit has been issued and in issuing licenses to new licensees under section 15 hereof the Commission shall give preference to applications therefor by States and municipalities, provided the plans for the same are deemed by the Commission equally well adapted, or shall within a reasonable time to be fixed by the Commission be made equally well adapted, to conserve and utilize in the public interest the water resources of the region; and as between other applicants, the Commission may give preference to the applicant the plans of which it finds and determines are best adapted to develop, conserve, and utilize in the public interest the water resources of the region if it be satisfied as to the ability of the applicant to carry out such plans.

This is not to say that the financial capability of a municipal applicant is irrelevant at the licensing state to a consideration of which application proposes the "best adapted" plan. Normally, inquiry into the economic ability of any license applicant to carry out its plan occurs in the context of whether its plan is "equally well adapted to conserve and utilize in the public interest the water resources of the region." It would not serve the public interest in hydropower development to award a license to a person that lacks adequate resources to develop a project, especially when other interested parties have such resources. Therefore, the Commission is revising § 4.33 as indicated in the notice of proposed rulemaking.

D. Evidence of Legal Competence of a Municipal Applicant Under State Law to Enter the Power Business

The rulemaking, as proposed, would require municipal applicants for permit or license to submit evidence of competence under state law to develop, transmit, utilize, or distribute power.

One commenter suggests that evidence of competence should not be required of a municipality which already holds a valid license for some other hydropower project. The applicable state law may authorize municipal endeavors in various ways, so as to limit the authority of a given municipality in some way unrelated to an outstanding license for another project. In any event, applicable state and local laws may have changed since the granting of the earlier license, and the Commission would have to expend considerable time to determine if these laws were still applicable. If the applicant's proposal relates directly to an existing licensed project, such as an application for license for a transmission line only on an amendment of license, the Commission does agree that being the licensee of that project obviates this requirement.

Another commenter asserts that a "joint-power agency" should not have to show that each member municipality is competent if the joint-power agency is competent. The new requirement does not mean that a joint-power agency applicant must submit evidence of competence for each member municipality. The evidence required when a joint-power agency is the applicant would be evidence regarding the competence of that agency or of municipalities as a class.

One commenter also suggests that a sworn statement by a municipal electric utility should be sufficient to prove competency. The Commission wishes to avoid any delays in project development as a result of legal incapacities. Since a sworn statement by a municipality would presumably be based on its own research into the applicable statutes and judicial decisions under which the municipality seeks to develop a project, the Commission's proposal would not therefore entail any significantly greater effort in order to supply copies of the relevant law.

One commenter asserts that a legal competency test should not be rigid, because state laws are changing in this area, posing a further question about whether the proposed sanction of denying the municipal preference status is inappropriate and too harsh. On the other hand, utility companies point to various examples of limitations upon municipalities' authority and legal restraints that may affect their financial capability, as opposed to their legal competency, to engage in the power business.

The Commission believes that the Federal Power Act intended to encourage hydropower development by municipalities by providing a significant competitive advantage to qualified public applicants. The definition of "municipality" in section 3(7) of the Act clearly requires that such public entity be competent under the law in order to qualify as part of that class of applicants that may enjoy this competitive advantage. Denial of the preference based on a lack of the requisite legal competency is therefore not a sanction but a statutory requirement. In the final analysis, it is the responsibility of each municipal applicant to know the current state of the law, for its own as well as the Commission's purposes. The variety and the mutability of the laws to which the commenters refer is a principal reason for the requirement that evidence of legal competency be submitted.

Three commenters advocate treating the absence of the required evidence of competency as a deficiency is order to give the municipality another opportunity to provide information without losing the preference. If a municipality fails to submit sufficient evidence of competence, this fact will be included in the Commission's assessment of any application deficiencies and, if the cumulative deficiencies do not warrant rejection of the application, the municipality will be granted the usual time to submit the needed information before the priority status obtained by filing is lost. By clarifying its application requirements, the Commission wishes to minimize the use of the process whereby applicants are afforded additional time to cure deficiencies in their applications, further delaying Commission action.

The Commission agrees with those commenters who argue against interpreting the competency requirement as requiring that all legal action associated with competency to be in the power business need be completed at the time of application. For example, bonding for a municipal project may prove impractical or impossible until after a feasibility study is completed. Such action should not, and would not, be required as a condition precedent to filing an application for permit. It is sufficient that the municipality is legally capable of undertaking project development.

It is suggested, on one hand, that the Commission solicit an opinion from each state attorney general as to the competency of municipalities to engage in power development, use, or sale. On the other hand, different commenters find municipalities to be the most capable parties to ascertain their own legal qualifications; they are, after all, the most interested party in the determination. The Commission agrees. The suggestion that the Commission solicit state attorney general opinions from all states is impractical. Such opinions might prove only temporarily valuable since they would be valid only as long as state law remained unchanged. The Commission requests reference to any appropriate legal authority in those circumstances were the general statutes and the relevant municipal charter do not expressly authorize the activities for which the applicant seeks authorization. The new rule enables the Commission to eliminate deficiency letters used to determine legal status which in any case is generally known to the municipal applicant. The requirement therefore helps expedite the application review process without unduly burdening the applicant.

For the reasons stated, the Commission is adopting revisions to §§ 4.33, 4.51(a) and 4.81(a) but without specifically requesting attorney general interpretations.

E. Material Amendments to Applications

Under the proposed rule, a material amendment to a pending permit or license application will result in its being considered a new application. The time priority to which the applicant may be entitled is then established according to the filing date of the amendment.

Most of the comments assert that a specific differentiation should be made between those amendments which alter the status of the applicant as opposed to those which only change the design, capacity, or structure of the proposed project. Changes in design, new technologies, or an improvement in an overall plan as a result of new studies should be allowed without loss of priority, according to most commenters, because the Commission's goal ought to be to develop the best possible project. If making such changes would jeopardize the original date of application, applicants will arguably be deterred from implementing improved features in their projects. In addition, most commenters maintain that the rule provides no standard for determining the "materiality" of a change, such as a change in a project description or a new location for an appurtenant facility. One commenter believes there should be a change in the filing date only if there is a significant reduction in the capacity or output of a proposed project. Another commenter states a change should arise only if there is a fundamental change in the application such as a decrease in efficiency, a material increase in cost, or an impairment of development.

The Commission has added to its final rule specific statements of what will be considered a material amendment to a plan of development in a permit or license application sufficient to warrant considering the amendment a new application requiring a different time priority. These changes are of such a fundamental nature as to constitute the proposal of a different project. However, given the amount and quality of data available to a permit applicant, the proposals submitted at that stage of conceptualization are seldom so altogether different from one another as to permit a clear judgment to be made on the merits, rather than on first-in-time. In the case where an applicant that did not file first-in-time nevertheless has a clearly better plan of development and its competitor then seeks to utilize those ideas to make its plan equally well adapted, fairness militates against allowing the first-filed application to retain its priority in-time for its amended application. While the Commission agrees that the best possible plans of development must be encouraged, the Commission also wishes to encourage applicants to submit the best plans which they can devise the first time they file.

The Commission also believes that a change in the nature of the applicant for permit or license is sufficiently important to require treatment of the application as if it were submitted at the time of amendment. The status of an applicant may be an important factor in the Commission's permitting or licensing decision if there are competing applicants (*see* 18 CFR 4.33). Moreover, there is a public interest in knowing precisely who is proposing to develop a site, for purposes of protest and intervention, not to mention any Commission assessment at the licensing stage of the applicant's financial capabilites.

The new rule regarding amendments to applications, contrary to our commenter's assertions, will not necessarily prevent two separate applicants with different sites on the same river from subsequently undertaking a joint development. Such projects may be mutually exclusive or they may be successfully coordinated. The Commission's proposal encourages such developers to work together early in the planning stages and thus to submit a single licensing proposal. If the applications were separately submitted, it would be unfair to competitors to permit subsequent consolidation into a single application deemed to have been filed at the time of the original proposals.

In response to a comment that the rule might work to the disadvantage of entities which have a preference under section 7(a) of the Act, the Commission points out that the material amendments rule will not necessarily operate to deprive a state or municipality of a statutory preference. Application of the first-in-time principle is not generally important to the selection process where one applicant is a state or municipality and one is not. (§ 4.33(g).) However, an applicant must have a timely filed application in order to take advantage of any preference or priority or even to argue that its project is best adapted. It would inhibit efficient consideration of competing applications if a public entity were permitted, as a commenter proposed, to upgrade its application *at any time* and still maintain its preference or priorities. If a public entity amended its application within the initial notice period and its competitor is a non-public entity, the preference under section 7(a) would be unaffected. Expeditious licensing nevertheless requires that fundamental proposals be submitted as early as possible, regardless of the nature of the applicant. Amendment of an application may therefore prejudice any applicant's ability to compete under the new rule, if not timely filed.

III. Section-by-Section Analysis of the Final Rule

1. *Interventions. §§ 1.8(f)(2) and 4.31(h).* The rule automatically grants a person who files under § 1.8 a timely petition to intervene in a preliminary permit proceeding the status of party to that proceeding, unless and until the Commission or other decisional authority denies or stays such a petition or unless that petition is opposed by the preliminary permit applicant or other party under § 1.8(e).

2. *Co-applicants. § 4.30(d).* The Commission, as a matter of policy, requires that any persons having or intending to obtain any property or other interest necessary to construct, operate, or maintain a water power project for which a preliminary permit or license is sought from the Commission, be included on the appropriate application as a co-applicant. Failure to include all such persons may result in a loss of a filing priority or preference. (*See* § 4.35.)

3. *Notice of intent. § 4.33 (a) and (b).* The Commission will not accept notices of intent to submit competing preliminary permit applications for specified kinds of projects. However, a prospective competitor may file with the Commission a competing permit application not later than 30 days after the time specified for protests and interventions in the public notice of the initial permit application. This affords approximately 90 days, instead of the current 60 days, to file competing permit applications. The rule eliminates 30 days from the total maximum time available for permit applications, if a notice of intent were submitted.

4. *Evaluating competing applications. § 4.33(g) (3) and (4).* To conform with section 7(a) of the Federal Power Act, the test to be applied to competing applications for permit or license, where one applicant is a public entity and another is not, is revised by deleting reference to the ability of the respective applicants to carry out the proposed plans of development. Generally, the Commission's selection turns on other elements specified in the regulations, namely the relative merits of the plans of development, the nature of the applicants, or the timing of the applications.

5. *Evidence of competence under section (3)(7) of the Act. §§ 4.33(i), 4.51(a)(4), 4.81(a)(4).* A municipal applicant for preliminary permit for any project or for license for a major project—existing dam must supply evidence that it is competent under state law to be in the power business. If it fails to do so, it will be treated as a non-public applicant under § 4.33. The Commission will also include similar provisions in the revised regulations for minor, major unconstructed, and major modified water power projects, at the time those regulations are issued in final orders.[8]

6. *Change of filing dates as a result of material amendment. § 4.35.* The rule creates a new section to indicate that any material change in an application for preliminary permit or license after it is filed with the Commission, such as by changing the status or identity of the applicant (*e.g.* from citizen to municipality) or by making significant fundamental changes in the plan of development, will result in its treatment as a new application and a change in the date of acceptance for filing to the

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[8] See Notices of Proposed Rulemaking in Footnote 1, *supra.*

date on which the amendment is filed. If the amended application competes with any other application and the revised acceptance date is later than the last date for filing protests and intervention on the initial application, the amended application will not be considered timely filed and will be rejected. The final rule specifies the most common types of changes that would result in treatment of an amended license application as a newly submitted application. However, only the changes in the plan of development in a permit application described will affect the priority of the application. For both permit and license applications, a change in the nature or identity of the applicant will change the status of the application. A change in this date of acceptance could change an applicant's priority status relative to competing applicants under § 4.33.

IV. Effective date

This rule, including the amendment to § 4.30 which is promulgated without prior notice and comment, is being made effective immediately. The primary objective of the rule is to streamline the Commission's procedures for handling preliminary permit and license applications. This is necessary not only to diminish the licensing burdens imposed on regulated entities, but also to cut down on the administrative delay that attends processing and approving preliminary permit and license applications.

In addition, if the Commission provided the customary 30-day delay in the effective date, applicants could decide when to file an application for a permit or license based on how best to use the changes in the regulations to disadvantage their competitors. The confusion and delay that could result from this practice would be contrary to the public interest. For any proceeding which begins after the effective date of the rule, the stage at which the interests of an applicant or a prospective competitor will be irrevocably affected by substantive impacts of the major changes in the regulations—the removal of the notice of intent, the grant of automatic intervention, or the amendment of application provisions—will not be reached until the end of the notice period for any initial application, that is, not sooner than 60 days. Affected persons are therefore afforded a reasonable time to prepare for the consequences of the final rule by the nature of the Commission's procedures, particularly the notice periods. Other changes in the regulations do not impose burdens that outweigh the public interest in more expeditious administrative procedures.

For the reasons stated above, the Commission finds good cause to make the rule of proceeding effective immediately.

For the same reasons, and because the provisions would provide for a general policy that has been long-standing Commission practice and procedure, the Commission finds good cause to include in the rule the new provision of § 4.30 without prior notice or comment.

This rule will not apply to any proceeding, whether for preliminary permit, license, or exemption from licensing, which is pending on or before [date of issuance].

(Federal Power Act, as amended, 16 U.S.C. 782–828c; the Department of Energy Organization Act, 42 U.S.C. 7101–7352; E.O. 12209, 3 CFR 142 (1978))

In consideration of the foregoing, the Commission amends Parts 1 and 4, Chapter I, Title 18 of the Code of Federal Regulations, as set forth below.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,306]

46 F. R. 55252 (November 9, 1981)

18 CFR Part 4

[Docket No. RM80-65; Order No. 106-A]

Clarification of Regulations Governing Exemption From All or Part of Part I of

the Federal Power Act of Small Hydroelectric Power Projects With an Installed Capacity of 5 Megawatts or Less

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Clarification of final rule.

SUMMARY: The Federal Energy Regulatory Commission clarifies its final rule in Order No. 106, which established procedures for case-by-case exemption of certain hydroelectric projects from provisions of the Federal Power Act, by stating the considerations relevant to determining whether it is permissible to consider a project at a breached dam to be exemptible under the statute as a project that utilizes an "existing dam" for power generation. The clarification is designed to inform applicants of the Commission's policies with respect to the exemption of projects which propose to use a breached dam.

DATE: This clarification is made effective as of November 7, 1980, the effective date of Order No. 106.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

Issued: October 29, 1981.

I. Clarification

The Federal Energy Regulatory Commission (Commission) clarifies its approach to providing exemptions from licensing under the case-specific procedures established under Order No. 106 [1] for small hydroelectric power projects that utilize for electric power generation an existing dam which has been breached and which therefore may require some repair or reconstruction. Specifically, the Commission is informing applicants for exemption from licensing of those factors which it considers if called upon to determine whether a dam is an "existing" dam or, because of the extent or impacts of the construction required to mend a breach in the dam, it is a new dam to which the exemption provisions will not apply. Under the Energy Security Act of 1980 (ESA),[2] the Commission is authorized to exempt from licensing or other provisions of Part I of the Federal Power Act, any small hydroelectric power project that utilizes an "existing dam." [3] One of the major questions of fact presented to the Commission in an application for exemption of a project that utilizes the water power potential of an existing dam is whether, in fact, the dam is "existing". Under the PURPA, a dam, to be considered "existing", must have been completely constructed on or before April 20, 1977. It must also not require any construction or enlargement of impoundment structures, other than for repairs or reconstruction, in connection with installation of any small hydroelectric power project.

PURPA permits exemption of a project with a dam built on or before April 20, 1977, even if the dam is in need of some rebuilding. The question is, how much construction may be considered restorative as opposed to the substantial construction of a new dam? Order No. 106 addresses this issue in the Comment Analysis:

> Two commenters argue that projects at "existing dams" include those at breached dams, no matter how badly breached a dam may be, and that the Commission should clarify this in the rule. Such projects should be made exemptible if the project owner

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[1] 45 FR 76115, November 18, 1980.

[2] Pub. L. 96-294, 94 Stat. 611.

[3] The definition of "existing dam" in the Commission's regulations (§ 4.102(b)) is identical to that of section 408(a)(6) of the Public Utility Regulatory Policies Act of 1978 (PURPA). The ESA amends PURPA by adding the exemption authority in section 405(d).

proposes to reconstruct the dam, they say. The commenters point to section 408(a)(6) to PURPA which defines "existing dam" for purposes of small hydroelectric power projects as "any dam, construction of which was completed on or before April 20, 1977, and which does not require any construction or enlargement of impoundment structures (other than repairs or *reconstruction)* * * *" (Emphasis added). One commenter states that the Department of Energy, in granting PURPA loans, considers this to have the effect of including among existing dams even badly breached dams. It is not clear that a dam so badly breached that nothing remains but abutments is an "existing dam." Section 408(a)(1) of PURPA defines a small hydroelectric power project as one located "at the site of an existing dam," and this definition limits the scope of our authority to grant exemptions. The explantory statement of the Conference Committee which accompanied the original Title IV of PURPA states that "the phrase 'at the site of an exsting dam' should be strictly construed to mean at the site of an existing impoundment." Badly breached dams will have no impoundment and an argument may be made that such dams do not qualify for the financial assistance program under Title IV. Whether Congress intended such dams to be excluded from exemption under the 1980 amendment to PURPA is unclear.[4]

Fundamentally, the question of whether a breached dam is an "existing" dam is an issue of fact, suited only for case-specific determination. If a dam is breached, the qualifications of a project for exemption will therefore be considered only on a case-specific basis. However, this approach requires two clarifications. First, the Commission will not consider as an existing dam for exemption purposes a breached dam at which little or none of the original impoudment continues to exist. Second, there are several additional factors which will be taken into account when determing whether there is an existing dam.

The limitations in section 408 of the ESA—that only existing dam projects and projects which do not require a dam or impoundment be exempted—suggest that any extensive new construction and inundation of additional land was not contemplated by Congress as a consequence of exemption. Therefore, the degree to which any repair or reconstruction will raise the level of whatever water may be impounded will be relevant. An equally important aspect of any proposed change in circumstances which would result from dam reconstruction is the length of time since the dam was breached and the previously inundated land was laid bare. Nature will have substantially reclaimed the environs around a drained reservoir over time, the extent of that reclamation being a function of the amount of time since the land was laid bare. If a breach is recent, however, the effects of refilling the reservoir pursuant to repairs would be less problematic to the environment, although construction impacts are always important to consider. The effect of any reconstruction on migratory fish populations at the site of a breached dam is an additional factor to weigh in determining appropriate terms and conditions of exemption.

For the above reasons, any project which contains an impoundment which is at substantial variance from the historic, non-flood power generation level or, if no power was previously developed at the site, the impoundment level which the dam was originally designed to contain, will be scrutinized to determine whether the return of the impoundment level to its historic or power generation level would entail significant adverse environmental effects. If the Commission so finds, the project will not be considered "at the site of an existing dam."

II. Effective Date

Because this clarification does not change the Commission's exemption regulations or its policy regarding the application of those regulations, it will be considered effective as of November

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[4] Order No. 106, *supra, mimeo* at 24–25; 45 FR at 781———. The omitted footnote refers to H.R. Rep. No. 95-1750, 95th Cong., 2d Sess. 106 (1978).

7, 1980, the effective date of Order No. 106 (45 FR 76115, November 16, 1980). The Commission finds that notice and comment is unnecessary for interpretations of existing regulations such as this clarification.

(Federal Power Act as amended 16 U.S.C. 792–828c Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601–2645, the Department of Energy Organization Act 42 U.S.C. 7101–7352, E.O. 12209, 3 CFR 142 (1978))

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,307]

46 F. R. 55253 (November 9, 1981)

18 CFR Part 282

[Docket No. RM80-18]

Treatment Under the Incremental Pricing Program of Natural Gas Used in the Manufacturing Process for Fertilizer, Agricultural Chemicals, Animal Feed or Food; Effective Date and Availability of Exemption Affidavits

Issued: November 2, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of effective date and availability of exemption affidavits.

SUMMARY: On September 24, 1981, the Federal Energy Regulatory Commission (Commission) issued a rule (46 FR 50060, October 9, 1981) under Title II of the Natural Gas Policy Act of 1978 (NGPA) providing an exemption from incremental pricing for natural gas used as boiler fuel in the manufacture of fertilizer, agricultural chemicals, animal feed or food. The rule was transmitted to Congress for review, as required by section 206(d) of the NGPA. During the period for Congressional review set forth in section 507(b) of the NGPA, neither House disapproved the submittal. The exemptive rule thus became effective on November 1, 1981, the day following expiration of the review period.

EFFECTIVE DATE: November 1, 1981.

FOR FURTHER INFORMATION CONTACT:

Barbara K. Christin, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357–9370, or

Alice Fernandez, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357–9095

SUPPLEMENTARY INFORMATION: Affidavits for claiming an exemption from incremental pricing have been revised to reflect the subject exemption and are available through the Commission's Division of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426, or from natural gas suppliers. By order issued November 2, 1981, the Commission waived its regulations in § 282.204(d)(7) (18 CFR Part 282) to provide that if the owner or operator of an industrial boiler fuel facility files, by November 25, 1981, an affidavit with the Commission claiming the subject exemption, and sends a copy to the facility's natural gas supplier, the facility shall be exempt from incremental pricing as of November 1, 1981.

Kenneth F. Plumb,
Secretary.

[¶ 30,308]

46 F. R. 55926 (November 13, 1981)

18 CFR Parts 2, 4, 5, 16, and 131

[Docket No. RM80-39; Order No. 184]

Application for License for Major Unconstructed Projects and Major Modified Projects; Application for License for Transmission Lines Only; and Application for Amendment to License

Issued: November 6, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) amends the regulations governing three kinds of licensing under Part II of the Federal Power Act (Act) for: (1) Major water power projects that have an installed generating capacity greater than 1.5 megawatts and that would either utilize the water power potential of a dam that, at the time application is filed, is not constructed ("major unconstructed project") or that would change the state of existing project works so as to produce a significant increase in the normal maximum surface area or elevation of an impoundment or otherwise produce a significant environmental impact ("major modified project"); (2) only the transmission lines that transmit power from a licensed water power project or other hydroelectric project authorized by Congress to the point of junction with the distribution system or with the interconnected primary transmission system; and (3) any amendment to a license that would entail a change in the physical features, plans, mode of operation, or construction period of the project or its boundary.

The rule would also make conforming changes in §§ 4.31, 4.50, 16.7, 131.2, and Appendix A of Part 2 of the Commission's requirements. The regulations would reorganize the license applications. The regulations are designed to ease the burden of preparing applications and to assist the Commission in processing applications for license. The rulemaking is therefore expected to expedite hydropower development.

DATE: This rule is effective December 14, 1981.

FOR FURTHER INFORMATION CONTACT:

Ronald Corso, Director, Division of Hydropower Licensing, Office of Electric Power Regulation, Federal Energy Regulatory Commission, 825 N. Capitol Street, NE., Washington, D.C. 20426, (202) 376-9171

James Hoeker, Division of Rulemaking & Legislative Analysis, Office of the General Counsel, Federal Energy Regulatory Commission, 825 N. Capitol Street, NE., Washington, D.C. 20426, (202) 357-9342

SUPPLEMENTARY INFORMATION:

Issued: November 6, 1981.

The Federal Energy Regulatory Commission (Commission) amends three regulations governing applications for license under Part I of the Federal Power Act (Act). First, the Commission revises the licensing regulations governing major water power projects with an installed generating capacity greater than 5 megawatts (MW) that would utilize the water power potential of a dam that, at the time application is filed, is not constructed ("major unconstructed project") or that would change the state of existing project works so as to produce a significant increase in the normal maximum surface area or elevation of an impoundment or otherwise produce a significant environmental impact ("major modified project"). Second, the Commission revises the regulations governing applications for license for transmission lines that transmit power from a licensed water power project or other hydroelectric project authorized by Congress to the point of junction with the distribution system or with the interconnected primary transmission system. Third, the Commission revises the regulations governing applications for any amendment to a license that would entail a change in the physical features, plans, mode of operation, or construction period affecting the project or its boundaries.

The rule would also make conforming changes in §§ 4.31, 4.50, 16.7, 131.2, and Appendix A of Part 2 of the Commission's regulations.

I. Background

This final rule is the third phase of a program of licensing reform for all projects within the Commission's jurisdiction built for the generation of electric power by means of water power. The Commission issued its Notice of Proposed Rulemaking in this docket on January 23, 1981 (46 FR 10165, February 2, 1981).

The first phase of the program was instituted in 1978, when the Commission issued the so-called "short-form" application procedures for all "minor" projects, *i.e.*, those with a capacity of 1.5 MW or less.[1] On October 22, 1979, the Commission issued procedures applicable to both preliminary permit and license applications, and which simplify the procedures for application for preliminary permits, amendments to permits, and cancellations of permits.[2]

On November 19, 1979, the Commission issued rules which established application procedures for licensing major projects that are located at existing dams and have a generating capacity greater than 1.5 MW.[3]

The Commission has also issued related rules to encourage development of specialized kinds of hydroelectric facilities. It recently established procedures to exempt from all, or part of, Part I of the Act any small conduit hydroelectric facility that has a generating capacity of 15 MW or less.[4] Similarly, the Commission issued rules on November 7, 1980, setting forth procedures to exempt from licensing and other requirements of the Act any small hydroelectric power projects having a proposed generating capacity of 5 MW or less.[5]

The existing requirements for the types of license applications which are affected by the rulemaking in this docket are located in various parts of Title 18 of the Code of Federal Regulations. Subtantive requirements applicable to one or all of these applications are found in §§ 2.80 and 2.81, Appendix A to Part 2, §§ 4.40, 4.41, 4.70, 4.71, 5.1 through 5.4, 16.7, 131.2, 131.3, and 131.4 of the Commission's regulations. A potential applicant now faces the prospect of meeting information requirements embodied in up the 23 separate exhibits.

The final rule set forth in this docket is designed to ease the burden of compliance in several ways. First, it reduces the information needed for the Commission to carry out its duties under law in an informed and responsible manner.[6] For example, the provisions requiring extensive documentation of the nature of the applicant and its authority to file the application have been eliminated or reduced, and requirements relating to evidence of compliance with state laws have been simplified.[7] In any case, an applicant will continue to be obligated to comply with any applicable state law not preempted by Part I of the Act.

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[1] Order No. 11, "Regulations Governing Applications for Short-form License (Minor)" (Docket No. RM78-9), issued September 5, 1978, 43 FR 40215, September 11, 1978. The 1.5 MW capacity criterion was based on the fact that the Commission is authorized under Section 10(i) of the Act (16 U.S.C. 803(i)) to ease certain requirements for minor projects. "Minor" projects should not be confused with so-called "small" hydroelectric power projects with an installed capacity of 30 MW or less at existing dams which are encouraged under the Public Utility Regulatory Policies Act of 1978 ("PURPA") (16 U.S.C. 2705 et seq.). PURPA mandates simplified and expeditious licensing for such small water power projects, and, as amended by the Energy Security Act of 1980 (94 Stat. 611), permits the Commission to exempt from licensing and other requirements of the Act certain small hydroelectric power projects 5 MW or less. The first phase of the Commission's reforms therefore covered only a portion of the projects identified under PURPA.

[2] Order No. 54, "Regulations Prescribing General Provisions for Preliminary Permit and License Applications; and Regulations Governing Applications for Amendments to and Cancellation of Permits" (Docket No. RM79-23), issued October 22, 1979, 44 FR 61328, October 25, 1979.

[3] Order No. 59, "Regulations Governing Applications for License for Major Projects—Existing Dams" (Docket No. RM79-36), issued December 18, 1979, 45 FR 75383, December 20, 1979.

[4] Order No. 76, "Exemptions of Small Conduit Hydroelectric Facilities from Part I of the Federal Power Act" (Docket No. RM79-35), issued April 18, 1980, 45 FR 28085, April 28, 1980.

[5] Order No. 106, "Exemption from All or Part of Part I of the Federal Power Act of Small Hydroelectric Power Projects with an Installed Capacity of 5 Megawatts or Less" (Docket No. RM80-65), issued November 7, 1980, 45 FR 76115, November 16, 1980.

Second, the Commission has consolidated the requests for information according to related subject matter. All paragraphs and exhibits requesting information on environmental matters[8] have been consolidated into Exhibit E (Environmental Report), required under § 4.41(f). Improved organization of the application requirements should reduce confusion and redundancy in the materials submitted.

Finally, the rule will help minimize the element of subjective interpretation in the Commission's requirements by reducing the requests for information, where possible, to simple, objective, descriptions of what is necessary. The Commission believes that clearer, simpler requirements and cooperation between the Commission and applicants will help avoid the application deficiencies that have slowed the licensing process in the past.

Projects to the type covered by this rulemaking usually result in more significant environmental impacts than do water, power projects at existing dams which do not entail significant construction or alteration of the impoundment level. Under the new regulations, the Commission therefore requires of any applicant for license for a major unconstructed project or a major modified project an Environmental Report of considerably greater detail than it does for smaller projects and most projects at existing dams. Under any of the Commission's hydropower licensing regulations, the Environmental Report (Exhibit E) submitted by the applicant must be commensurate with the size and type of water power project for which the applicant seeks a license or with the scope of any proposed amendment to an existing license.[9]

Under the final rule, an applicant for license for any project with an installed generating capacity of 5 megawatts or less may file under the Commission's abbreviated application procedures.

The Commission has issued a companion rulemaking which provides abbreviated application procedures for all projects with a total generating capacity of 5 MW or less.[10]

However, this change will not alter the current requirement that a more extensive Environmental Report (Exhibit E) be filed for any major unconstructed or major modified project with an installed capacity in excess of 1.5 MW.

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[6] Section 405 of the Public Utility Regulatory Policies Act of 1978 (PURPA) (16 U.S.C. 2705) provides that the Commission's simplified licensing procedures must be "consistent with the applicable provisions of law" and that no project covered by the procedures will be exempted from "any requirement applicable to any such project under the National Environmental Policy Act of 1969, the Fish and Wildlife Coordination Act, the Endangered Species Act, or any other provision of Federal Law."

[7] *See* existing §§ 4.40(b) and 4.41—Exhibits A–F. These requirements have been distilled to simple statements in the initial portion of the application under § 4.41(a). Since the entire application is subscribed and verified under § 1.16 of our rules, the applicant's statements will suffice as evidence. Additional information will be requested in cases where it is needed. Consistent with the policy announced in the Notice of Proposed Rulemaking in Docket No. RM81–15, issued February 20, 1981, 46 FR 14751, March 3, 1981, the Commission will request from municipalities evidence of competency under state law to engage in the electric power business.

[8] *See* existing §§ 2.80, 2.40(k) and (l), 4.41 (Exhibits H, R, S, V, and W), and Appendix A to Part 2.

[9] Section 2.80 through 2.82 constitute most of the Commission's existing environmental review regulations, under the National Environmental Policy Act of 1969 (NEPA). Under this rulemaking, the environmental report requirement of Appendix A of Part 2 will cease to apply to any application relating to hydroelectric project licensing and will be replaced by the specialized Exhibit E in each licensing regulation.

[10] "Regulations Governing Applications for License for Minor Water Power Projects and Major Water Power Projects 5 Megawatts or Less," (Docket No. RM81–10), issued January 21, 1981. Many of the section numbers cross-referenced in the rules in this docket and in Docket No. RM81–10 derive from the new, rather than existing, regulations.

II. Analysis of Comments

Most commenters express overall approval of the Commission's efforts to simplify licensing requirements pursuant to section 405 of PURPA. The single greatest source of concern is the type and amount of information required of a license applicant. A variety of comments declare that the Commission's proposed license application requirements are too burdensome. Others argue that more information should be required.

A. License application for Major Unconstructed Projects and Major Modified Projects

1. *Exhibit E. (Environmental Report)*

a. *General Comments.*

Exhibit E, the Environmental Report, received particular attention. Some public utilities claim that the proposed rule represents an increase in the amount and level of detail of data over that required in existing license requirements. This is an incorrect assumption. The final rule does not contemplate submittal of a greater variety of information than that required under existing §§ 4.40 and 4.41. Specifically, the data requirements under former Exhibits R, S, V, and W and the environmental report set forth in Appendix A of § 2.81, have been consolidated and reorganized. The Commission has reduced filing requirements, where possible, consistent with its previous hydroelectric rulemakings. However, of all of the revised Exhibits E established to date, the environmental report required for projects included in this rulemaking is the least susceptible to major reductions in data requirements because of the environmental consequences associated with the construction of a new dam and impoundment.

Most of the data now required under Appendix A, including that related to the temporary and permanent impacts of project construction on water use and quality, fish and wildlife resources, historic resources, socioeconomic and aesthetic features, is necessary to perform a thorough environmental analysis of a project that will fundamentally alter the ecology and geography of an area. The applicant's Exhibit E will form the basis for the Environmental Impact Statement that will usually be prepared for projects licensed under this rule. The data required is also important to the success of the consultation with agencies having responsibility to review project impacts that occurs during any licensing proceeding. In light of the variety of impacts that flow from dam construction and the creation or substantial alteration of the affected impoundment, an applicant must supply the Commission with a complete, self-explanatory description and analysis of the project and its impact in order to expedite consideration of the proposal under NEPA, the Fish and Wildlife Coordination Act, the Endangered Species Act and other Federal laws.

Some commenters, including the Environmental Protection Agency (EPA), suggest that an applicant be permitted to incorporate by reference environmental documentation containing the information required in the Exhibit E. While the applicant is not precluded from referring to standardized and reliable information, Exhibit E should be a self-explanatory exhibit which adequately describes the anticipated environmental impacts of the individual proposed project. Submittal of a satisfactory exhibit will require case-specific studies and an application that lends itself to a well-rounded understanding of the nature and effects of project development.

As a number of commenters emphasize, the rule requires only information which is commensurate with the scope of the proposed project. The final rule so specifies. However, it is important to note that projects with the greatest potential impacts on the environment will be licensed under this rule and an applicant should be prepared to explain the omission of any required data or analysis. If the applicant's own analysis, in light of consultation with state or Federal agencies, indicates that the effect on resources (e.g., historical resources.

water quality, etc.) would be minimal, the report to the Commission may be reduced accordingly.

In commenting on the Initial Regulatory Flexibility Analysis, the law offices of Spiegel and McDiarmid (Spiegel) argues that the Commission's distinction between "major" and "minor" projects is unreasonable and proposes that a more meaningful delineation would be between "constructed" and "unconstructed" projects for purposes of assessing environmental impacts. The Commission notes that section 10(i) of the Federal Power Act provides that the Commission may waive certain conditions and requirements of the Act for projects with an installed capacity of 2000 horsepower (1.5 MW) or less. Historically, the Federal Power Commission and this Commission have utilized this statutory language to reduce the application requirements for any license for such "minor" projects and to impose less stringent conditions on their continued operations, regardless of whether a particular dam was proposed or existing. However, the Commission has also carefully differentiated in its rules between "constructed" and "unconstructed" projects that would have an installed capacity in excess of 1.5 MW, so-called "major" projects. The license application requirements, including data requests, are substantially less for projects at existing dams. (§§ 4.50 and 4.51.) This rulemaking extends to projects under 5 MW the benefits of abbreviated license applications, although an Exhibit E under § 4.41(f) will be required for unconstructed major projects and projects otherwise subject to major modification. The "major-minor" distinction will also continue to delineate differences in standard terms and conditions of license, barring any future change in section 10(i).

Some commenters propose that Exhibit E seek information in more general terms or require only "estimates" rather than quantified data. The Commission rulemakings cited above have produced significant reductions in the level and volume of information required of applicants for license for minor projects and major projects at existing dams. While this final rule accomplishes similar goals, major unconstructed and modified projects present a different set of environmental, engineering, and regulatory problems. Such projects typically are "major Federal actions significantly affecting the quality of the human environment" within the meaning of Section 102 of the NEPA. In order to expedite project licensing and minimize deficencies and delay, Exhibit E is clearer and more specific in its data requests than prior equivalent exhibits, without imposing data-gathering requirements that are unnecessary to the Commission's statutory duties. However, adequate review of a proposed project requires that the information submitted be specific, accurate, and sufficiently quantified to convey a precise picture of the project and its probable effects. To the extent that an application contains generalities, the Commission must resort to time-consuming data requests.

On several occasions, commenters claim that the consultation requirements of the proposed regulations are both too open-ended and do not require agencies to respond to the applicant's requests for consultation and documentation within a "reasonable" time. The Commission has consequently amended the consultation requirements in its licensing regulations to require that the applicant need only wait for a specified time period after requesting an agency to consult and to provide documentation of the consultation process before submitting an application containing its own evidence of consultation. The applicant may submit a summary of the consultation process or attempts to consult with designated agencies, if agencies are not responsive. The Commission emphasizes, however, that, apart from the consultation process, all interested agencies have an opportunity to comment on any filed application. The pre-application consultation is designed to expedite this process.

The Commission disagrees with some commenters who believe that the consultation process represents an additional, unnecessery burden on the applicant. Pre-application consultation is a necessary element in the application process to avoid the costly and time-consuming delays in licensing and to promote expeditious environmental evaluation of proposed laws of development. Other interested agencies would be disadvantaged by being notified of a project development only after the plan is filed. The consultation process is also designed to prevent premature application-related expenditures by an applicant who might find, after discussions with appropriate agencies, that the project is wholly or partly infeasible. Consultation is required by the Fish and Wildlife Coordination Act and the Endangered Species Act and is advisable whenever other Federal or state agencies have responsibilities under law which affect project development and operation.

The Commission recognizes the point made by commenters that pre-application consultation may involve placing a prospective applicant's plan in the public record of another agency, thereby affording competitors an opportunity to examine those plans. Some commenters fear that the availability of such information will provide unfair advantages to a party who would utilize another's data as its own. However, the Commission believes that the benefits which derive from consultations countervail the potential problems which may result from them. An applicant who determines that an unfair advantage may accrue to persons who might resort to plagarism may seek whatever protections may be available. The Commission expects that each applicant will perform its own studies and present its own application for license; however, each applicant is also expected to pursue effective pre-application consultation.

Spiegel states that the consultation requirements may not satisfy the requirements of section 9(b) of the Act under which the applicant must submit evidence of compliance with state laws governing beds and banks, and the appropriation, diversion and use of water for power purposes and competency to engage in the power business. The Commission points out that consultation normally does not serve to obtain such information. It is a process designed to provide a basis for analysis of the environmental problems relating to certain Federal actions. Portions of the Initial Statement in license applications, such as § 4.41(a)(5), request submittal of the appropriate information required by section 9(b).

Terrestrial Environmental Specialists, Inc. (TES) inquires whether requiring the applicant, not the Commission, to consult is contrary to the Fish and Wildlife Coordination Act. Once an application is filed, all interested agencies are served with the application by the Commission or the applicant and provided time to comment directly. This is the primary means by which the Commission consults with other agencies under this and other statutes. However, the Commission uses the pre-application consultation process to promote compliance with the provisions of that act and other laws, in an expeditious manner. Consultation has proven its value to applicants and agencies alike by promoting more thorough consideration and understanding of environmental issues.

In response to several comments that expressed confusion over the administration of the consultation process, the Commission points out that the applicant should carry out the consultation by contacting the agency, presenting the proposal for comment, and providing a reasonable opportunity for the agency to comment and to provide documentation of the applicant's consultation efforts. The Commission will provide a list of appropriate agencies with which to consult but it is not itself an environmental agency and prefers not to mediate between the applicant and agencies consulted. The applicant should expect agency comments to address those issues which the agency is competent to discuss. The applicant's response to the agencies' positions should be stated in the application, and the Commission will review the issues and resolve any disputes through informed decision making.

b. *Report on water use and quality.* Numerous comments propose clarifying and corrective amendments to portions of Exhibit E.

The EPA voices concern that applicants may not analyze the eutrophication potential behind the dam and the downstream water quality impacts of the project. The Commission expects both aspects of water quality impact to be addressed under § 4.41(f)(2)(iv), to the extent practicable. That section specifically mentions the thermal, turbidity, and nutrient effects of the project.

Two comments focus on the requirement to describe mitigation measures under § 4.41(f)(2)(v). R. W. Beck and Associates (Beck) states that the cost of mitigation measures should be a line item in the applicant's discussion of project costs. While the costs of mitigation are relevant to project development, the Commission believes any presentation of such costs is speculative. It does not preclude the need for a narrative description of measures proposed by agencies and the applicant. Commission review of this item is important for establishing terms and conditions for the license. Pacific Gas & Electric Company (PG&E) argues that the regulations should not require detailed mitigation information at the time of application. However, Commission staff must know the scope of proposed mitigation measures at the earliest possible time to fully understand the impacts that may occur due to development and operation of the project. Such mitigation measures may be the outcome of the pre-application consultation and will clarify the overall evaluation of project viability. This, of course, does not preclude an applicant from performing further study after an application is submitted.

c. *Report on fish, wildlife and botantical resources.* Alabama Power Co. (Alabama) states that mitigation or environmental protection measures should be described by applicants only if adverse impacts are expected. The Commission believes that at least some adverse impacts are inevitable from the kinds of construction which would be authorized under this regulation. Rather than invite argument over the nature of these impacts and suffer delays due to deficiencies in the filed application, the application requirements should be complete and fully explanatory. If there were no impacts, there would of course be no proposed mitigation measures.

In order to avoid any duplicative requirement, the Commission deletes from § 4.41(f)(3)(iii) of the final rule any reference to archaeological resources since that topic is the focus of § 4.41(f)(4). In response to comments, the Commission also clarifies the data requirement in § 4.41(f)(3)(i) to require analysis of impacts on fish species important because of their commercial or recreational value.

Some commenters find § 4.41(f)(3) unclear, as proposed. It requires a separate and detailed description of impacts on fish, wildlife and botanical resources, including possible effects on the size, distribution, or reproductive capacity of these ecological features. The term "production," rephrased "reproduction," refers to the amount of aquatic life the project area is able to sustain. One commenter recommends elimination of this data request in favor of an approach advocated by the U.S. Fish and Wildlife Service as an alternative to population estimates. We conclude that this "carrying capacity" analysis is a valid means of determining mitigation requirements in a variety of circumstances where loss of habitat value is a possibility. This analysis would effectively supplement information on the impacts on fish and wildlife populations. The Commission, however, is not of the view that other information requested in paragraph (f)(3)(i) is unnecessary. The complexity of the effects arising from dam construction requires a more circumspect analysis of possible environmental damage than would be afforded by the carrying capacity analysis alone.

In response to a procedural inquiry, the Commission notes that any drawings submitted in this exhibit need not conform to the specifications in § 4.32.

d. *Report on historic and archaeological resources*

Some commenters anticipate that lack of access to any private property at the project site could be a hindrance to performing the archaeological survey work required under § 4.41(f)(4). The Commission has not found evidence that any lack of access to the site has been an insurmountable problem. Were an applicant unable to gain physical access, information on such resources is generally available elsewhere. It is essential that such information be collected in order to ascertain the probable impacts on archaeological resources and to devise means to mitigate those impacts. Environmental protection and efficient processing of applications countervail the suggestion that such information be obtained after filing because of the possibility that an applicant's development plans might, to some extent, be revealed when it requests permission to enter onto private land.

EEI suggests that on-site surveys should be required only in areas where a "high probability" of historic or archaeological resources exists and that, before submittal of an application, only an overview of the site should be required. The Commission believes that delaying detailed analysis of environmental resources in favor of a cursory examination and a determination of what constitutes a "high probability" of sensitive environmental features would be an inefficient use of Commission resources that would delay the licensing procedure. Applications should be as complete as possible when submitted. However, even on-site inspections are fallible. For example, historic and archaeological resources are not always discoverable until unearthed by construction. This is the exception to the rule, however.

The Commission agrees with EEI that references to the Heritage Conservation and Recreation Service, recently dissolved, should be deleted from the final rule. The National Park Service is substituted, where appropriate. The requirement that the applicant consult with the State Archaeologist is deleted as well. Consultation with the State Archaeologist may be an advisable step to expedite preparing and processing the application; however, consultation with the State Historic Preservation Officer as provided by statute will serve to protect archaeological resources.

The Commission wishes to note that it foresees little of the difficulties anticipated by one commenter with respect to the requirements of the Commission and those of the Bureau of Land Management regarding rights-of-way for linear project features like transmission lines. The Commission finds the requirements of the two agencies to be generally consistent and subject to any necessary reconciliation during the consultation process.

e. *Report on socio-economic impact.*

Commenters criticize the socio-economic reporting requirement in § 4.41(f)(5) of Exhibit E as being too difficult to provide and having no legal basis. As a general proposition, standard economic projections and accepted forecasting procedures are sufficient to perform the analysis required in the report. Much of this information may be obtained as part of the required consultation process, from data compiled by local and state agencies. The socio-economic information requested in the new Exhibit E is not greater than that normally required under existing regulations.

It has long been the policy of the Commission to consider in licensing determinations the relative socio-economic impacts of proposed projects, such as the probable effects on local economies and human resources. The Commission issues licenses based on a variety of factors; it believes that socio-economic information is an important element in the determination of the feasibility and practicability of the proposed project. Under the NEPA, agencies must use a systematic, interdisciplinary approach, including the natural and social sciences, to evaluate actions that significantly affect the quality of the human environment. NEPA therefore contemplates the analysis of socio-economic impacts for such major actions. Moreover, the Commission has responsibilities under the Federal Power Act to protect life, health, and property and to obtain a range of information to assist its statutory duties to issue licenses for hydropower development. The information required in this rulemaking is more comprehensive than that required for projects at existing dams since the environmental impacts associated with new construction are usually more significant.

f. *Report on geological and soil resources.*

Some commenters believe the geological and soils data required in § 4.41(f)(6) should be placed in Exhibit F, which consists of design drawings. However, the soil and geological data required in Exhibit E does not address the structural limitations of the project site as depicted in Exhibit F, but instead depicts the qualitative aspects of the project lands. The proposal has therefore not been adopted.

g. *Report on recreational resources.*

Several commenters termed unnecessary the "buffer zone" requirement of § 4.41(f)(7). This requirement is continued from existing regulations. It was established by the Commission in Order No. 313,[11] pursuant to the Commission's responsibilities under section 10(a) of the Act and the policy on outdoor recreation and resources delared by the Congress.[12] Order No. 313 states that applicants are required to provide such buffer zones within the project boundary. Whether there are factors that make such buffer zones unneeded or uneconomical for a particular project must be determined on the basis of the information submitted by the applicant. The new regulation does not change the policy of Order No. 313, but simply requires that the matter be addressed at the outset of a licensing proceeding when preparing the application.

Washington Water Power Company (Washington) suggests that § 4.41(f)(7)(iii) should pertain only to "reasonable" public access. The standard articles included in a project license [13] condition approval of a project on the provision of reasonable public access to the project area, consistent with the protection of life, health and property. These conditions are not provided specifically in the application requirements. The applicant should instead suggest what might constitute reasonable access with such considerations in mind.

Alabama argues that it would be fruitless to describe recreational facilities and land uses that will abut the project in the future since it might not own the abutting property. The Commission recognizes that the applicant will not necessarily have the authority to commit abutting properties to specific land uses. As a matter of practicality, the applicant need only provide such information to the extent that the applicant has knowledge of any proposed plans or prospective agreements.

In response to another inquiry by Alabama regarding detailed cost estimates of the construction, operation, and maintenance of existing and proposed recreation facilities, the Commission believes that such information is an important indication of the quality of facilities and the parties responsible for dependable operation and maintenance of them. The recreation report should be sufficiently detailed to describe the facilities and the recreation plan for the project. This does not preclude the applicant from filing "as-built" drawings after construction.

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[11] 30 FR 16198, December 22, 1965, 34 FPC 1546 (1965).

[12] Section 1, Outdoor Recreation Programs Act of May 28, 1963, 16 U.S.C. 460.

[13] Form L-1, Articles 17 and 18, Order No. 540, 40 FR 51998, November 7, 1975.

Spiegel argues that the Commission is without authority to condition a license on consideration of the needs of the handicapped. The Commission previously ruled in Order No. 508 [14] that recreation facilities at hydroelectric projects must be designed to accomodate the handicapped. This is a policy worth continuing and is not designed to provide a "barrier-free wilderness," as the commenter argues, but reasonable access to major recreational features.

h. *Alternatives to location and design.* The new regulations introduce a new section addressing "alternatives" to the location and design of the project and to hydropower development itself (§ 4.41(f)(10)). NEPA requires agencies to consider alternatives to proposed actions. The Commission has created this provision to deal separately with those alternatives that focus on issues other than the strictly environmental ones, such as designs and site locations. Most commenters suggest that all references to alternatives should be located in this section. Some commenters argue that a discussion of alternative sites for a project is superfluous since the viability of another hydropower site should not preclude development of the proposed site.

The requirement that applications discuss alternative sites does not suggest that development of the proposed site would preclude the future development of any other site, but only that, in the interest of comprehensive and efficient utilization of limited water resources, the Commission must analyze the process of site selection in relation to other available sites and possible developments.

2. *Exhibit F.* Some commenters appear to misunderstand the Commission's requirements with respect to final design drawings for the project. It should be noted that the regulations do not require final design drawings prior to licensing. Final drawings are required before construction may begin. The supporting design report required to be filed with the Exhibit F in § 4.41(g)(3) should be consistent with the drawings submitted. If the drawings are preliminary in nature, the report should be preliminary also.

B. General Comments on the Rulemaking

Several commenters suggest that the Commission provide a chart explaining the various changes made to the regulations. Two such charts have been developed to indicate the various options available to a prospective applicant under the Commission's former regulations and the revised licensing regulations. They are attached as an Appendix to the copies of this rule that are available at the Commission's Office of Public Information during regular business hours.

Sections 1.5 and 1.16 of the Commission's rules of practice and procedure apply to all filings made with the Commission, including license applications. Niagara Mohawk Power Company (Niagara) recommends that the rule be revised to be consistent with existing § 1.5 of the Commission's regulations which requires an application to be in writing and under oath. It is unnecessary to repeat the subscription requirement in those sections again in § 4.41. The Commission also points out that 18 U.S.C. 1621 prohibits any false subscription to a material fact made in a statement under oath and submitted to the Federal Government, with resulting civil and criminal sanctions for a violation of the statute.

Niagara also suggests that applicants be required to recite the statutory provisions under which a filing is made. This provision of § 1.5 tends to be superfluous. Given the organization of the Part 4 regulations and the requirement that each Initial Statement be clearly labeled according to the type of authorization sought, statutory citations would be of assistance to neither the applicant nor the Commission. Section 1.5 is proposed to be replaced (*See*, Notice of Proposed Rulemaking in Docket No. RM78-22, issued March 4, 1981). Applications lacking the citations required in that provision will not, for that reason, be deemed deficient.

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[14] Form L–1, Article 17, 54 FPC 1799, 1804 (1975); 18 CFR 2.7(b), 51 FPC 1425 (1974), 39 FR 16338, May 8, 1974.

The Commission has also added paragraph (a)(6) to § 4.71 to require evidence of compliance with applicable state laws in accordance with the requirements of section 9(b) of the Act. This conforms to similar application requirements in §§ 4.41 and 4.51.

TES states that the regulations should require information on a transmission line "corridor" rather than a specific right-of-way under §§ 4.41 or 4.71. Such information is acceptable. It is the normal procedure for the Commission to authorize transmission line construction within a corridor, leaving later acquisition of a right-of-way within that corridor to the licensee. Therefore, an applicant may depict a preferred corridor in the application, rather than a right-of-way as such.

One commenter argues that the change in the title of Appendix A to Part 2, an environmental report requirement, is a major change in the Commission's NEPA provisions because it imposes environmental requirements on actions undertaken by the Commission or a regulated entity pursuant to sections 202(b), 210, 211 and 212 of the Federal Power Act. The proposed amendment was designed only to indicate that Appendix A is replaced by the Exhibits E in Part 4, for water power projects, leaving other actions under the Act covered by Appendix A, to the extent an environmental report may be required. A change in title alone imposes no substantive requirements to prepare an Environmental Report for, say, wheeling or interconnection cases. It may otherwise be determined that these actions would entail construction which must be investigated under NEPA. Nevertheless, the title is revised to avoid this misunderstanding.

C. Amendment of License

Most comments on the regulations governing amendments to license suggest establishing a threshold level of proposed modification beyond which a licensee would be subject to competition by interested parties. Spiegel states that any proposed change in capacity of 1.5 MW or greater should be considered a "new project" subject to competition under the general licensing regulations.

The Commission acknowledges that a licensee's proposal to change the configuration or operation of its licensed project may not, in all cases, be consistent with the plan of development contemplated when the project was licensed. As a general matter, amendments to a license, whether they add capacity, change project works, or otherwise reshape the project, are not so fundamental as to create a different licensed project, thereby necessitating public notice, intervention, and protest procedures. It would, in any case, be very difficult to prescribe universal criteria applicable to all projects indicating which amendments are permissible and which are not. For example, an increase of 1.5 megawatts of installed capacity may be incidental in one case and important in another. Such a change might necessitate major operational changes or virtually none at all, depending on the size, location or operational characteristics of the project. In any case, section 6 of the Act prohibits amendment of a project license without the mutual consent of the licensee and the Commission. In those instances where significant new project works are proposed to be added or a major change in existing works or mode of operation is proposed, the Commission may withhold its assent or issue public notice in order to permit participation in a proceeding by interested persons. However, the Commission may not initiate a process that might defeat a license based on a proposed amendment.[15] The final rule does not establish, in terms of installed capacity or other criteria, a threshold beyond which a new license is required rather than an amendment to an existing license. The Commission requests that, prior to submittal of any application for amendment, the licensee consult with the Commission to ascertain whether the proposed changes in the license is within the scope of the project. The final rule also encourages such a practice.

PG&E argues that the amendment of license requirements should not apply except to changes in capacity greater than 5 MW. As stated above, the consequences of change in project operation or configuration will vary from project to project. Terms and conditions may permit a change in one instance but not in another. Therefore, the Commission is reluctant to arbitrarily establish a threshold for applicability of §§ 4.200 and 4.201 based only on an amount of proposed installed capacity.

Some commenters express uncertainty about whether the installed capacity levels referred to in proposed § 4.201(b) pertain to the increment of additional capacity proposed in an application for amendment of license or the total installed capacity including any new generating capacity proposed by the licensee. The Commission clarifies this provision to indicate that *total* installed capacity after the amendment of a license is what determines the appropriate exhibits for submittal.

In response to a comment from EEI, the regulations now permit, in the interest of flexible application of the requirements and minimizing unnecessary filings, an applicant to submit only the revised portion of an exhibit affected by the amendment. The Commission maintains in its permanent records all exhibits and amendments submitted by an applicant-licensee.

D. Paperwork Reduction Act of 1980 (PRA)

One commenter perceives the revised Exhibit E, § 4.41(f), as an undue paperwork burden and requests review and approval of the regulation by the Office of Management and Budget under the PRA. The Commission has long recognized the practical need for, and legislative interest in, the reduction or elimination of unnecessary regulatory burdens. The final rules in this docket and in Docket No. RM81–10 manifest this recognition. The rulemaking in this docket completes the major portion of the Commission's three-year program to reorganize, clarify, and reduce all of its preliminary permit and license application requirements.

The Commission's revised hydropower regulations have thus far helped reduce, by an average of 50 percent, the time which the Commission requires to process preliminary permit and licensing applications for all types of projects. Regulatory delay increases the capital expenditures on projects by as much as one percent per month, if a 12 to 15 percent inflation rate is assumed. The duplicative, lengthy, and discursive hydropower application requirements which existed before the Commission's recent revisions (existing §§ 4.40 and 4.41 being the vestigial remains of those regulations) not only imposed an undue burden on applicants, they resulted in poorer quality applications, deficiency letters, and a lengthier period between filing and a final Commission order. It is important to note that the final rule in this docket, in conjunction with that in Docket No. RM81–10, also permits up to 50 percent of all major unconstructed projects to be licensed under the so-called "short-form" application procedures.

The provisions of the Exhibit E are designed to carry forward the same policies and to conform to the same format established in previous Commission orders revising the hydropower licensing requirements.[16]

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[15] The reference to § 4.33 in existing § 5.4, which a commenter pointed out, is an errant and outdated cross-reference and does not imply that the competing application provisions in existing § 4.33 apply to any amendments of license, as such. Part 5 is revoked by this rule.

[16] See, orders cited in Footnote 1, *supra*.

Those orders resulted in substantial savings to applicants by requiring only such information as the Commission considers essential to carry out its statutory responsibilities under the Federal Power Act and the numerous environmental statutes which relate directly to its licensing authority. The Commission anticipates that its final action in this docket will provide similar regulatory relief, first, by making its requirements clear and, second, by enabling the Commission to act expeditiously on applications.[17]

The construction of a dam and impoundment involves an intricate network of ecological, socio-economic, and aesthetic ramifications which the Commission is obligated by statute to study and help mitigate. Its responsibilities range from considerations of public health and safety to protection of wild and scenic rivers, endangered species, and anadromous fish runs. A proposal to develop capacity at an existing dam does not entail the level of engineering and environmental problems, and normally does not occasion the amount of public interest and participation, as does a proposed new dam. This accounts for the greater detail requested under the new § 4.41, particularly Exhibit E. The Commission has taken into account both the level of information which it considers necessary to discharge its responsibilities and that which an applicant for license can reasonably be expected to provide, given the nature and complexity of the kinds of projects to be approved for construction under the final rule.

With respect to OMB review of agency forms, the Commission will comply with all applicable provisions of law.

E. Regulatory Flexibility Act (RFA)

One commenter claims that the Commission's Initial Regulatory Flexibility Analysis (Initial Analysis), contained in the Notice of Proposed Rulemaking in Docket No. RM81–10 but applicable to this rulemaking also, is deficient in estimating the burdens and benefits of the rules and in analyzing reasonable alternatives. The commenter also asserts that the requirements proposed in this docket constitute an entry barrier to small entities interested in developing hydroelectric power projects and that the distinction made between major and minor projects based on installed capacity is unreasonable.

A Final Regulatory Flexibility Analysis of the two rulemakings has been prepared as required by section 604 of the RFA and is published in the preamble to the final rule in Docket No. RM81–10. The Commission's analysis in that document bears on the issues raised by the commenter, including consideration of alternatives to the proposed rule and the regulatory burden on small entities. The Commission also offers the following views.

As stated above, in its discussion of the Paperwork Reduction Act, the Commission's basis for undertaking this rulemaking is to reduce the regulatory burden on all prospective non-Federal developers, not to devise new and expensive filing requirements as prerequisites to a license. The Commission believes that the final rules are more easily understood and better organized than previous licensing provisions; requests for superfluous information such as articles of incorporation and rate schedule information are deleted; exhibits are consolidated and the requirements clarified, without an overall increase in the volume of data requested. The exhibits on socio-economic and recreational impacts and access to project waters are not new, as the commenter supposes. They spring from statutory requirements that such values be studied. The Commission subscribes to the statutory purposes set forth in the

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[17] The effects of the hydropower licensing reform program on applicant's costs and the Commission's approval processes is discussed in the Final Regulatory Flexibility Analysis in Docket No. 81–10 which applies to the final rule in this docket as well.

RFA but disagrees with the commenter with respect to how those purposes ought to be carried out in the context of a rule such as this.

Neither the Federal Power Act nor the RFA contemplate providing authorization to use a public resource without taking into account the maximum effective utilization of that resource consistent with the public interest in producing reliable power, preserving lives, public health and safety, and environmental values.[18] An applicant for license must have a financially and technologically feasible plan of development and be capable of constructing, operating and maintaining a project in a manner consistent with the Congress' environmental mandates. The larger and more complex the proposed project, the greater the Commission's task in assessing its impacts and determining the conditions under which it must operate.

In Hydropower licensing, the need for the information required does not vary according to the nature or size of the applicant but according to the nature of the project. For that reason, the requirements have been segregated according to the installed capacity of the proposed project[19] and whether the plan of development requires that a new dam and impoundment be constructed. The revised requirements in §§ 4.40 and 4.41 are necessary means to evaluate the viability, feasibility, and environmental desirability of major projects without resort to prolonged case-by-case data requests by means of deficiency letters. They form the basis for preparing the Environmental Impact Statement which is almost invariably required under NEPA because authorization of major unconstructed projects is normally a major Federal action significantly affecting the quality of the human environment. Such considerations make it inadvisable to reduce further the amount of information the Commission may obtain about a project, as the commenter advocates, or to reduce the requirements which prospective developers of a certain size must meet, as the commenter implies.

"Small entities", including municipalities under 50,000 population (section 601(5) of the RFA), have not in the past confronted undue barriers to the licensing process. Even under the existing, more cumbersome procedures, such entities constitute up to 60 percent of all applicants for major unconstructed projects. Not only does the final rule simplify the requirements for major unconstructed projects over 5 MW, it places approximately 50 percent of such projects formerly licensed under §§ 4.40 and 4.41 under the "short-form" application requirements which prescribe submittal of four abbreviated exhibits instead of seven lengthier ones. As the Initial Analysis states, this will, if anything, enable small entities to compete more effectively for those kinds of projects in which they have been most interested historically.

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[18] In addition to the Federal Power Act, any of the following statutes may affect the licensing and development of a water power project: National Environmental Policy Act, Federal Water Pollution Control Act (Clean Water Act), Fish and Wildlife Coordination Act, National Historic Preservation Act, National Trails System Act, Water Resources Planning Act, Wilderness Act, Archeological and Historic Preservation Act of 1974, Bureau of Outdoor Recreation Organic Act, Anadromous Fish Act, National Forest Multiple Use Act, Coastal Zone Management Act, Endangered Species Act, Energy Policy and Conservation Act of 1975, Federal Land Management Policy Act, Wild and Scenic Rivers Act, and Energy Security Act.

[19] The Commission and its predecessor, the Federal Power Commission, have maintained a distinction between "major" and "minor" projects based on section 10(i) of the Federal Power Act. That provision permits waiver of some provisions or requirements of the Act for projects with not more than 2000 horsepower or 1.5 megawatts of installed capacity. Such waiver is manifested in the kinds of conditions contained in licenses for projects above ("major") and below ("minor") the 1.5 megawatt demarcation. *See* § 2.9. The "short-form" license application procedures now set forth in § 131.6 will be applied to minor projects and to major projects with an installed capacity of 5 megawatts or less under the final rule in Docket No. RM81-10. However, section 10(i) of the Act will continue to permit the less stringent conditions in licenses for minor projects. The Commission adopts the 5 MW demarcation for license application provisions to parallel Congress' determination that the Commission may grant exemption from all or part of Part I of the Act, including licenses of all water power projects located at existing dams and having a proposed installed capacity of 5 megawatts or less, so-called "small hydroelectric power projects." *See* §§ 4.101 *et seq.* of the Commission's regulations.

In addition, the benefit to "small entities" from this rulemaking is a benefit available to all prospective applicants, just as the burdens are applicable to all applicants. The costs of preparing an application and complying with state and Federal regulatory requirements will vary dramatically depending on the project and its location. Commission staff estimates that the cost of compliance with *all* state and Federal requirements for major unconstructed projects, including the license application provisions, will vary considerably up to as much as $1,500,000. The precise cost-savings to any particular applicant from a more (or less) stringent regulation would therefore be difficult to estimate.

There are, in any case, benefits which flow from a thorough and systematic collection of data. Efficient consultation and effective compliance with state and Federal agency requirements, coordinated through the Commission's processes, will lead to swifter licensing and substantial cost-savings. For example, 12 percent inflation will add one percent per month to the up-front cost of a project; if—as happened pursuant to Order No. 59 for major projects at existing dams—the approval process can be shortened by one year, the eventual licensee of a $10 million project could save as much as $1,200,000 in building the project.

The consultation procedures prescribed in the Commission's revised hydropower licensing rules and the reduction in deficiency letters or rejections which arose from unclear requirements will yield similar benefits to applicants for license for major unconstructed projects in the form of faster preparation and processing of the application and therefore faster development.

In sum, the commenter clearly wants the Commission to go farther in easing its filing requirements. A balanced consideration of the competing interest in expeditious and economical hydropower development and the protection of non-economic values, consistent with the requirements of the RFA, indicates that the approach to data collection originally proposed in this docket serves the best interests of small entities as well as the general public.

III. Final Regulatory Flexibility Analysis

The Commission's statement concerning the impact of this rulemaking on small entities is combined with the analysis of the final rule governing short-form license applications in Docket No. RM81-10, issued as a companion to this rulemaking.

IV. Summary of the Regulations

A. (Subpart E) Major Unconstructed Projects and Major Modified Projects

§ *4.40 Applicability and definitions.*

This section states that §§ 4.40 and 4.41 apply to any application for an initial license for a major unconstructed project, and an initial license or new license for a major modified project. Applications for license of major water power projects with an installed generating capacity of 5 MW or less must be filed under §§ 4.60 and 4.61 of the Commission's regulations. Section 4.40 defines "major unconstructed project", "major modified project", "initial license", and "new license", and offers the assistance of the Commission staff in determining whether §§ 4.40 and 4.41 apply to the applicant's proposed project.

§ *4.41 Contents of application.*

This section describes the contents of an application for a license for a major unconstructed project or a major modified project. The rule requires applicants to consult with appropriate local, state, and Federal resource agencies, including those responsible for socio-economic impacts such as the State Historic Preservation Officer, prior to filing their applications for license. These regulations follow other Commission procedures by affording other agencies an opportunity to review the proposed development and to be part of the planning process before the application has been filed wth the Commission. Otherwise, proceedings might often be delayed while agencies consider the effects of projects on their areas of responsibility and fashion recommendations. With pre-application consultation, key environmental issues will be identified and addressed at an earlier point in the process and the Commission's own required consultation with other agencies will be expedited.[30] The applicant must allow at least 60 days for each agency consulted to respond to the applicant's request for documentation of the consultation process which must then be submitted. At any subsequent time, however, the applicant may submit a summary of the applicant's consultation efforts. The Commission then will supply to each such agency a copy of the completed application, as filed, in order to provide further opportunity for comment.

(a) *Initial statement.* The initial statement provides certain basic information necessary for identification and orientation purposes, including the nature of the application, the name, business address, and telephone number of the applicant and its authorized agents, the status of the applicant, and the name and location of the project. The applicant is also required to state that it has complied with the laws of the state where the project is located with respect to obtaining property rights and the rights to appropriate, divert, and use water for power purposes, and with respect to obtaining authorization to engage in the business of producing, transmitting, and distributing power, and any other business necessary to accomplish the purposes of the requested license.[31]

(b) *Exhibit A.* This exhibit provides a description of the physical structures and features of the project. It the project includes more than one dam and associated facilities, each such discrete development must be described separately. The exhibit also includes a tabulation of any lands of the United States that are enclosed within the project boundary. This tabulation is necessary in order to record accurately the lands which have been reserved from entry, location, or other disposal pursuant to section 24 of the Act, 16 U.S.C. 818.

(c) *Exhibit B.* A statement of project operation and resource utilization is provided by this exhibit. The exhibit calls for a description of the available water supply and technical documentation of the manner in which the applicant proposes to utilize that water supply for the generation of power. The applicant must also explain how it intends to sell the power. Finally, the applicant must describe any plans it has for future hydroelectric development on the affected stream. The information in this exhibit will assist the Commission in determining whether the applicant's existing or proposed development and operation comport with optimum development of the waterway, as required by section 10(a) of the Act, 16 U.S.C. 803(a).

(d) *Exhibit C.* The third exhibit provides a proposed construction schedule for new construction on the project and a construction history for existing project works, including the dates of commencement and completion of construction and the date of first commercial operation.

(e) *Exhibit D.* This exhibit provides a statement of costs and financing. If the applicant seeks a new license for a proposed change in the existing state of project works or project operations which would result in a significant increase in the normal maximum surface area or elevation of an existing impoundment, and is not a municipality or a state, it must provide an estimate of the amount that would be payable (net investment) if the United States exercised its right to take over the project upon expiration of the license pursuant to section 14 of the Act, 16 U.S.C. 807.

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[30] Several statutes, including PURPA, require the Commission to consult with other agencies. Section 405 of PURPA provides that, prior to issuing a license for a project which fits the PURPA criteria, the Commission must "provide opportunity for consultation with the Council on Environmental Quality and the Environmental Protection Agency with respect to the environmental effects of such project." This duty will be carried out in accordance with our established procedures for consultation during the license application review process. Moreover, in certain circumstances, other agencies may have concurrent jurisdiction with respect to authorization of a project. Prior consultation by applicants will facilitate coordination with these other agencies. *See* section 10(c) of the Act, 16 U.S.C. 803(c).

[31] *See* section 9(b) of the Act, 16 U.S.C. 802(b).

If the applicant seeks an initial license, and any portion of the proposed project consists of previously constructed, unlicensed water power structures or facilities, a statement of the original cost of those project works and the corresponding land and water rights must be provided. The Commission is required by section 4(b) of the Act, 16 U.S.C. 797(b) to obtain information on the original cost of a project in order to determine the economic viability of the project and the quality of the applicant's plan.

Estimated costs of any proposed new development and estimated annual costs must also be provided, as well as information concerning the value of project power to the applicant and the sources and extent of financing and annual revenues available to meet the estimated costs. This information would enable the Commission to assess the economic and financial viability of the project.

(f) *Exhibit E.* This exhibit provides a report on the environmental resources of the project, the effects of the project on those resources, the proposed measures to mitigate the impacts or to protect and enhance the resources, and an environmental assessment of alternative sites, facility designs, and energy options. The greater detail required in this Exhibits E, compared to the Exhibit E for other projects, is justified on the basis that there are greater impacts associated with the construction of dams and the creation of impoundments, or any significant modification of an existing dam which would increase the maximum surface area or elevation of the impoundment or otherwise cause a significant environmental impact. The level of detail required should be commensurate with the nature and scope of the proposed project.

The Environmental Report contains a general description of the environment of the proposed project area and detailed analysis of water use and quality; fish, wildlife and botantical resources; historic and archaeological resources; socio-economic impacts; geological and soil resources; recreational resources; aesthetic resources; and, land uses.

An applicant must explain why it considers any measures proposed by any agency consulted not to be appropriate.

(g) *Exhibit F.* This exhibit consists of general design drawings of the principal project works. The drawings must show plans, elevations, profiles, and sections for each structure, and must be accompanied by sufficient information concerning structural strength and stability and other controlling factors to demonstrate that the structures are safe and adequate for their state function.

The applicant may file either preliminary or final design drawings with the application, and five copies of a supporting design report must accompany the drawings, describing the basis for the design depicted in the design drawings. The supporting design report must include design assumptions and the result of all design analyses in sufficient detail for staff to make an independent assessment of the safety and adequacy of the proposed project works. The final design drawings must be submitted prior to construction of the project.

(h) *Exhibit G.* The final exhibit is a map of the project. The map must show the geographical location of the project, the physical interrelationships of project works and other features, a project boundary enclosing the project purposes, and any lands of the United States that are within the project boundary.

The following table indicates how the information required under the former regulations has been eliminated or transferred to the new regulations:

Former regulations [1]	New regulations [2]
§ 4.40(c)	§ 4.41(b) Exhibit A.
§ 4.41 Required Exhibits:	
A	§ 4.41(a) Initial Statement.
B	§ 4.41(a) Initial Statement.
C	§ 4.41(a) Initial Statement.
D	§ 4.41(a) Initial Statement.
E	§ 4.41(a) Initial Statement.
F	§ 4.41(a) Initial Statement.
G	§ 4.41(e) Exhibit D.
H	§ 4.41(c) Exhibit B.
I	§ 4.41(b) Exhibit A, § 4.41(c) Exhibit B.
J	§ 4.41(h) Exhibit G.
K	§ 4.41(h) Exhibit G.
L	§ 4.41(g) Exhibit F.
M	§ 4.41(b) Exhibit A.
N	§ 4.41(e) Exhibit D.
O	§ 4.41(d) Exhibit C.
P	* * *
Q	* * *
R	§ 4.41(f) Exhibit E.
S	§ 4.41(f) Exhibit E.
T	§ 4.41(c) Exhibit B.
U	§ 4.41(c) Exhibit B.
V	§ 4.41(f) Exhibit E.
W	§ 4.41(f) Exhibit E.

[1] For proposed unconstructed major project.

[2] For major unconstructed projects and major modified projects.

B. Transmission Lines.

Sections 4.70 and 4.71, governing applications for license for transmission lines only, would be revised to direct applicants to use the exhibits provided in § 4.41 or § 4.61, depending upon the installed generating capacity of the project served by the transmission line and whether the line is constructed at the time of a license application. All applications for license for transmission line only must include an initial statement indicating the name and address of the applicant, the name of the project to which the transmission line will be connected, and the proposed market for the power.

An application for license of any unconstructed transmission line connected to a water power project with an installed capacity of more than 5 MW must include the exhibits required under § 4.41, to the extent that those requirements are appropriate to transmission lines. Applications for license for any line that is already constructed or that is unconstructed but proposed to be connected to a project with a capacity of 5 MW or less must include the short-form exhibits required under § 4.61, to the extent that those requirements are appropriate to transmission lines.

The following table illustrates the transfer of Exhibits from the existing to the revised regulations:

Former Regulations [1]	New Regulations [1]
§ 4.71 Required Exhibits:	
A	§ 4.71(a) Initial Statement.
B	§ 4.71(a) Initial Statement.
C	§ 4.71(a) Initial Statement.
D	§ 4.71(a) Initial Statement.
J	§ 4.71(b), § 4.41(h) Exhibit G, § 4.61(d) Exhibit F, § 4.61(e) Exhibit G.
K	§ 4.71(b), § 4.41(h) Exhibit G, § 4.61(d) Exhibit F, § 4.61(e) Exhibit G.
M	§ 4.71(b), § 4.41(b) Exhibit A, § 4.61.
N	§ 4.71(b), § 4.41(e) Exhibit D.
O	§ 4.71(b), § 4.41(d) Exhibit C.
P	* * *
Q	* * *
V	§ 4.71(b), § 4.41(f) Exhibit E, § 4.61(c) Exhibit E.

[1] For transmission line only.

C. Amendment of License

Sections 5.1 through 5.4 are revoked, and the regulations governing applications for amendment of a license are transferred to a new subpart of Part 4 of the regulations. Under new Subpart L, all applications for amendment of a license must include an initial statement indicating the name, address, and telephone number of the applicant, a description of the proposed changes, and the reasons for the changes. Subpart L then refers applicants to §§ 4.41, 4.51, or 4.61 depending upon the installed generating capacity of the project and whether or not the dam and impoundment are constructed at the time the application is filed.

An application for amendment of a license for a major unconstructed or major modified project must include the exhibits required under § 4.41. An application for amendment of a license for a major project—existing dam must include the exhibits required under § 4.51. Lastly, an application for amendment of a license for a minor hydroelectric power project must include the exhibits required under § 4.61, but if the project is between 1.5 MW and 5 MW at the site of a dam proposed to be constructed after the issuance of the amendment, the

application must include an Environmental Report (Exhibit E) from § 4.41.

The following table shows how exhibits in the existing regulations governing license amendments are transferred or eliminated:

Former regulations [1]	New regulations [1]
§ 5.1	§ 4.200, § 4.201.
§ 5.2	§ 4.201.
§ 5.3	§ 4.200.
§ 5.4	* * *

[1] For amendment of license.

V. Other Changes and Deletions

In addition to the described amendments to §§4.40, 4.41, 4.70, 4.71, and 5.1 through 5.4, the Commission further amends the existing regulations. Section 4.50, which defines the applicability of the major project—existing dam regulations, is amended to indicate that §§ 4.50 and 4.51 do not apply to those projects that fall within the category of major modified projects. These regulations govern such projects and are referenced in § 4.50(a). Section 4.31 would be amended to reflect the nomenclature of §§ 4.40 and 4.41.

Section 4.51 is amended to make clear the applicant's responsibilities with respect to pre-application consultation with Federal, state, and local agencies. The requirements of the consultation process are noted at the beginning of § 4.51 and explained in detail in the appropriate exhibits.

Section 16.7 is revised to refer applicants for a "nonpower license" to the requirements of § 4.51 ("major project—existing dam").

Finally, the rule revokes four existing provisions of the Commission's regulations. The title of Appendix A to Part 2, which prescribes the Environmental Report required of applicants for license under the Act, is revised because the rule contains a new environmental report (Exhibit E). With the adoption of the final rule, Appendix A no longer applies to any type of hydroelectric license. Section 131.2, which prescribes the proper form for an application for license, is revoked since the proposed rule contains a new application format. Similarly, § 131.5, which prescribes the form for license for transmission line only, the § 131.30, which prescribes the form for amendment of license, are revoked because the final rule contains new formats for both types of applications.

VI. Effective Date

This final rule is effective December 14, 1981.

(Federal Power Act, as amended, 16 U.S.C. 792–828c; Public Utilities Regulatory Policies Act of 1978, 16 U.S.C. 2601–2645; Department of Energy Organization Act, 42 U.S.C. 7101–7352; E.O. 12209, 3 CFR 142 (1979))

In consideration of the foregoing, the Commission amends Parts 2, 4, 5, 16, and 131 of Chapter I, Title 18, Code of Federal Regulations, as set forth below, effective December 14, 1981.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,309]

46 F. R. 55944 (November 13, 1981)

18 CFR Parts 4, 16, 131, and 375

[Docket No. RM81-10; Order No. 185]

Application for License for Minor Water Power Projects and Major Water Projects 5 Megawatts or Less

Issued: November 6, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Commission adopts regulations governing so-called "short-form" applications for license for minor water power project and any water power project with an installed generating capacity of 5 megawatts or less. The requirements in the Commission's existing regulations are clarified by these regulations and the threshold installed capacity requirement for use of the short-form application is raised. This rulemaking is designed to expedite hydropower development by easing the burden of preparing an application for license and by assisting the Commission in more rapid processing of applications.

DATE: This rule is effective December 14, 1981.

FOR FURTHER INFORMATION CONTACT:

Ronald Corso, Director, Division of Hydropower Licensing, Office of Electric Power Regulation, Federal Energy Regulatory Commission, 825 N. Capital Street, NE, Washington, D.C. 20426 (202) 379-9171;

James Hoecker, Division of Rulemaking and Legislative Analysis, Office of the General Counsel, Federal Energy Regulatory Commission, 825 N. Capitol Street, NE, Washington, D.C. 20426 (202) 357-8342.

SUPPLEMENTARY INFORMATION:

Order No. 185

Issued: November 6, 1981.

In the matter of regulations governing applications for license for minor water power projects and major water power projects 5 megawatts or less.

The Federal Energy Regulatory Commission (Commission) amends the regulations governing applications for licenses under Part I of the Federal Power Act (Act) for water power projects with an installed generating capacity of 5 megawatts or less. The rule also revises §§ 4.60 and 4.61, and affects §§ 4.31, 4.50, 4.51, 16.12, 131.6, and 375.308 of the Commisson's regulations.

I. Background and Summary

On September 5, 1978, the Commission initiated the first phase of a program to revise its regulations to simplify and expedite hydropower licensing by adopting regulations governing so-called "short-form" application for license.[1] The Commission continued that program by completing additional rulemakings to revise the regulations governing the authorization of hydropower development.[2]

The Commission believes that further changes in the abbreviated license application requirements would expedite hydropower development. Consequently, it issued a Notice of Proposed Rulemaking in this docket on January 21, 1981 to expand the applicability of the "short-form" application to all projects of 5 megawatts or less, among other things.[3] The final rule established pursuant to that notice is designed to simplify the regulations and bring them into general conformance with other revisions to the license application regulations. Specifically, the exhibits required as attachments to an application have been redesignated as Exhibit A (description of the project and mode of operation), Exhibit E (Environmental Report)[4], Exhibit F (project drawings), and Exhibit G (maps). Most important, the final rule expands the applicability of the abbreviated or "short-form" application provisions to include all minor water projects and major water power projects with an installed generating capacity of 5 megawatts or less.[5] However, the Commission recognizes that proposed major (more than 1.5 megawatts) projects that have, at the time of application for license, no previously constructed dam or impoundment, and major modified projects that utilize existing dams but involve construction or operation changes that would significantly increase the maximum surface area or elevation of an existing impoundment, will usually have different and more substantial environmental impacts than will other major water power projects. The Commission will therefore require an application for license for such major unconstructed or major modified projects with an installed capacity between 1.5 and 5 megawatts to include an Environmental Report under § 4.41(f), rather than the short-form Exhibit E under § 4.61(c) which is otherwise applicable to all projects under 5 megawatts.

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[1] Order No. 11, "Regulations Governing Applications for Short-form License (Minor)" (Docket No. RM78-9), issued September 5, 1978, 43 FR 40215, September 11, 1978.

[2] Order No. 54, "Regulations Prescribing General Provisions for Preliminary Permit and License Applications; and Regulations Governing Applications for Amendments to and Cancellation of Permits" (Docket No. RM79-23), issued October 22, 1979, 44 FR 61328, October 25, 1979.

Order No. 59, "Regulations Governing Applications for License for Major Projects—Existing Dam" (Docket No. RM79-36), issued December 16, 1979, 45 FR 75383, December 20, 1979;

Order No. 76, "Exemptions of Small Conduit Hydroelectric Facilities from Part I of the Federal Power Act" (Docket No. RM79-35), issued April 18, 1980, 45 FR 28085, April 28, 1980;

Order No. 106, "Exemption from All or Part of Part I of the Federal Power Act of Small Hydroelectric Power Projects with an Installed Capacity of 5 Megawatts or Less" (Docket No. RM80-65), issued November 7, 1980, 45 FR 76115, November 18, 1980.

II. Comment Analysis

Commenters generally favor simplifying the license application requirements for minor projects and major projects 5 megawatts or less as proposed. However, some disagreement was expressed with respect to specific provisions of the rule, as follows.

A. Consultation Requirements

Several commenters state that the consultation requirements of the new rules do not define what is a "reasonable" time period within which resource agencies that must be contacted must in turn respond with pre-application comments on the proposed project. The proposed rule states that that period may in no case be less than 30 days. However, the Commission has revised the final rule to clarify that the applicant need only wait a specified time period after requesting that an agency consult before the applicant submits an application and substitutes its own documentation of the consultation process for that requested from the agency. After 30 days, the applicant may submit a summary of the consulation process or its attempts to consult with designated agencies. This does not foreclose further agency comment because all interested agencies are consulted by the Commission after an application is filed.

Pacific Gas and Electric (PG&E) believes that the pre-application consultation process is unfair to "initial" applicants since it enhances the possibility that any competitor may utilize information that is important to the initial applicant's proposal. The Commission recognizes that the pre-application consultation process might give another interested party an opportunity to plagiarize ideas. However, significant contervailing considerations militate against eliminating, or otherwise restricting, the requirement that a filed application be based in part on pre-application consultations. For example, pre-application consultation helps to avoid costly and time-consuming delays in the licensing process. It is designed to prevent premature application-related expenditures by an applicant who might find, after discussions with appropriate agencies, that the project is wholly or partly infeasible or otherwise poses unforeseen environmental problems. Consultation helps ensure better applications and expedites the final interagency consultation, such as that required by the Fish and Wildlife Coordination Act (16 U.S.C. 662) and Endangered Species Act (16 U.S.C. 1536). In any case, the Commission expects that all applicants will perform studies and consult with the appropriate resource agencies, regardless of the source of its plan of development, in order to help expedite the Commission's consultations and determinations.

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[3] 46 FR 9637, January 29, 1981.

[4] The Environmental Report has been revised slightly to be consistent with the report required under the Commission's rule governing case-by-case procedures for exempting small hydroelectric power projects from all or part of Part I of the Act. *See* 18 CFR 4.107(e)(Exhibit E).

[5] The Commission and its predecessor, the Federal Power Commission, have maintained a distinction between "major" and "minor" projects based on section 10(i) of the Federal Power Act. That provision permits waiver of some provisions or requirements of the Act for projects with not more than 2000 horsepower or 1.5 megawatts of installed capacity. Such waiver is manifested in the kinds of conditions contained in licenses for projects above ("major") and below ("minor") the 1.5 megawatt demarcation. *See* § 2.9. The "short-form" license application procedures now set forth in § 131.6 were previously applied only to minor projects. Under this rule, those procedures also apply (with the exception of an Exhibit E for unconstructed projects) to major projects with an installed capacity of 5 megawatts or less. However, section 10(i) will continue to permit the construction or operation under less stringent license conditions of minor projects.

The Department of the Interior (DOI) recommends that the Commission require applicants to consult with existing site owners to facilitate planning for future project operations. An applicant for license is not required to own the project site but is expected to acquire all necessary rights as a licensee, sometimes by exercise of eminent domain powers. At times this means that an applicant's and an owner's interests conflict. Therefore, the Commission may only urge that such coordination as DOI proposes take place. Generally, private negotiations for purchase or entry onto the land are conducted between the interested parties. The Commission will not undertake to require or supervise such consultation, however.

B. Procedures

Proposed § 4.61(a)(2) requires service of the filed application on Federal, state, and local agencies in order to help expedite the processing time necessary for "short-form" license applications by ensuring the earliest possible consideration of each plan of development by interested agencies. Niagara Mohawk Power Company (Niagara) voices concern over the logistics of service on the various agencies. Niagara urges the Commission to distribute copies of the application itself, claiming that it would be duplicative for the applicant to do so, having just consulted the agencies.

The Commission is particularly interested in avoiding the delays attendant to transmitting the large numbers of applications submitted for projects covered by this rule. It has therefore prepared a list of agencies to be consulted; it is available at any time from the Commission's Division of Hydropower Licensing. Because applicants have consulted with the agencies specified by the Commission during preparation of the application, they are in a good position to deliver copies of the application to those resource agencies. It is far less necessary that the straightforward short-form application be scrutinized by Commission staff before resource agencies are given the document. Both the applicant and the agencies will benefit from this method of distribution.

The final rule has been revised at § 4.60(c) to reflect the request of the Environmental Protection Agency (EPA) that the regulations require the applicant to furnish copies of the application when requested. In addition, that revised section addresses the concern expressed by DOI that the proposed reference to notification by "public notice procedures" did not include direct service of a notice of the application on interested agencies. Service of the notice is currently provided to interested agencies and no change in that policy is contemplated.

The Washington Department of Ecology (Washington) states that it prefers to continue processing applications for hydro-power projects under its state environmental policy act (SEPA). The Commission also wishes to continue the pre-application consultation that has worked so well with states such as Washington. The final rule will not affect the ongoing consultation practices designed to help protect environmental values.

C. Applicability and Installed Capacity

Commenters question how new increments of capacity added to existing licensed projects will affect the applicability of the short-form applications. PG&E advocates applying the short-form requirements based on increments of new capacity (*i.e.*, 5 MW or less) rather than the total installed capacity of the licensed project. It also argues that, if such small amounts of additional capacity are added, the Commission should require only the filing of a notice, as it proposed to do for projects exemptible under the categorical exemption rule of Docket No. RM81–7.[6]

In response, it should first be noted that a new licensing proceeding is not required for every increase in capacity. Increases in capacity for licensed projects may be provided for in the license or authorized as an amemdment to a license.[7]

The requirements for amending licenses and for licensing new projects, however, are established according to the total proposed installed capacity of the project and whether the dam and impoundment have been constructed. The Commission has determined that projects over 5 MW generally require greater scrutiny and more complex terms and conditions than smaller projects due to the magnitude of project construction, probable inundation, and other impacts. Incremental changes in capacity have effects that vary with the size, location, and type of development, thereby it is difficult to establish by rule the appropriate data needed in all cases. Nevertheless, the amount of data filed and the conditions imposed may be adjusted to suit site-specific characteristics under the regulation proposed.

PG&E also recommends that a minor license should be subject only to the same terms and conditions applied to categorically exempted projects. The privileges and obligations of a licensee and those of the owner of an exempted project are quite different. Licensees are held strictly accountable for the use of public resources. The Congress has allowed the Commission only limited discretion to exempt certain hydroelectric power projects from licensing. In implementing the exemption authority, the Commission has applied streamlined terms and conditions to two categories of projects with specific characteristics found by the Commission not to affect significantly the quality of the human environment. Licensing potentially applies to a greater assortment of projects than the limited exemption provisions and therefore requires greater scrutiny of a proposed project in order for the Commission to carry out its responsibilities to protect water resources, lives, public health and safety, and the environment.

In a related matter, DOI recommends that the Commission require all projects 5 MW or less to be sized to the "maximum economic potential." The concerns of DOI are anticipated in the Commission review of any proposal to ensure "comprehensive" development of water resources, consistent with protection of environmental values. The Commission will not favor a clearly undersized project, particularly when a better plan of development is proposed for the same or a mutually exclusive site. In both licensing and exemptions from licensing, the highest feasible installed capacity is encouraged both by the rules of competition and the economic realities of the marketplace which militate against building two or more small projects when one large one is practicable. However, the Commission looks to a variety of factors, including environmental considerations, to ascertain which is the best adapted plan of development. Moreover, "maximum economic potential" is a changeable kind of standard which may defy quantification and foster lengthy debate. The recommendation is therefore not adopted.

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[6] Notice of Proposed Rulemaking, "Exemption from Licensing Requirements of Part I of the Federal Power Act of Certain Categories of Hydroelectric Power Projects with an Installed Capacity of 5 Megawatts or less," issued December 22, 1980, 46 FR 1291, January 6, 1981.

[7] The final rule in Docket No. RM80–39, which accompanies this rule, revises the relevant license amendment regulations and permits greater flexibility in their application.

Order No. 184, "Regulations Governing Application for License for Major Unconstructed Projects and Major Modified Projects: Application for License for Transmission Line Only; and Application for Amendment to License," (Docket No. RM80–39), issued November 6, 1918.

D. Reporting Requirements

The Wisconsin Public Service Corporation (WPSC) argues that the requirement for mapping the project boundary should not be eliminated in § 4.61(e)(3) for projects with a capacity of 1.5 MW or less because conflicts between state and local governmental units might arise with respect to taxing authority. It appears to the Commission that there is little legitimate need for an extensive mapping requirement due to the limited area affected by such projects. The project boundaries for minor projects are generally regarded as the shoreline. The Commission wishes no broader application of its terms and conditions and, in any case, considers a project boundary to have little significance beyond the Commission's licensing provisions. If an applicant confronts special problems of this kind and therefore desires to have a boundary approved, it may ask for such consideration.

EPA suggests that the regulations allow an applicant to submit maps or photographs of environmentally sensitive areas to expedite review of the Exhibit E. The Commission revises the final rule accordingly to include this provision in § 4.61(c)(2)(ii). EPA also recommends that the project description include all roads. The final rule does so in § 4.61(e)(1).

Niagara proposes that the regulations in § 4.61(a)(3) be clarified to allow maintenance and repairs on existing project works prior to receipt of a license from the Commission. The final rule has been changed to reflect this suggestion by prohibiting prelicense construction work only on "proposed" project works. Repair of an existing dam which would be part of a proposed project could significantly affect the plan of development and the environment. Such work should be undertaken only to the extent necessary to protect lives or preserve the structural integrity of the dam. The project works as described in the application should not be changed substantially while the Commission reviews an applicant's proposal.

DOI requests that the application refer specifically to the National Inventory of Potential Wild and Scenic Rivers in order to facilitate protection of those resources. The Commission is aware of its responsibility to consult DOI on this and other environmental features potentially affected by developments. The breadth of information requested in the proposed exhibits is sufficient to enable the Commission and DOI to identify any possible threat to wild and scenic rivers and more specific references would not enhance further the protection of such resources.

DOI also proposes that the application contain more information on physical project works for use in evaluating the safety of dams. The proposed rule contained such data requests in § 4.6(a)(4) and the final rule is revised to require such information in an Exhibit A. Moreover, the projects licensed under this rule may also be subject to on-site inspection.

E. Other

DOI recommends a standard licensing article requiring the licensee to provide free public access to the project lands and waters. The Commission presently provides such access in Article 18 ("major license") and Article 13 ("Minor License") and will continue to do so.

Given the variety of new rules recently adopted by the Commission, two charts are provided to describe the options available under the former and revised regulations. They are attached as an appendix to the copies of the final order available at the Commission's Division of Public Information. The charts are filed as part of the original document.

III. Final Regulatory Flexibility Analysis for Docket Nos. RM81-10 and RM80-39

This analysis of the impact of the two rulemakings on "small entities" is prepared pursuant to the Regulatory Flexibility Act (RFA),[8] which requires certain statements, descriptions, and analyses of proposed rules that will have "a significant economic impact on a substantial number of small entities." These RFA requirements apply only to rules for which a notice of proposed rulemaking is issued on or after January 1, 1981. The broad purpose of the RFA is to ensure more careful and informed agency consideration of regulations that may significantly affect small business and small government entities, to encourage agency analysis of the burdens associated with regulations, and consideration of alternative approaches that would minimize the significant economic effects on these small entities.

In the preambles to both the final rule in this docket and the rule governing applications for license for major unconstructed and major modified water power projects[9], the Commission has presented its reasons for revising its hydropower licensing requirements, the legal basis for the rulemakings, and the reporting, recordkeeping, and other compliance requirements which they impose. An Initial Regulatory Flexibility Analysis (Initial Analysis) was prepared and published in the Notice of Proposed Rulemaking in this docket, in accordance with the requirements of section 603(b) of the RFA. Public comment on the Initial Analysis is addressed in the comment analysis in each docket and summarized below.

A Final Regulatory Flexibility is required by section 604(a) of the RFA to contain (1) A statement of the need for, and the objectives of, the rule; (2) a summary of public comment on the Initial Analysis and the agency's responses to such comment, and (3) an evaluation of alternatives to the action considered by the agency and the reasons for rejecting them. As stated in the Initial Analysis, both rules constitute part of the Commission's program to extend to all applicants for license for hydropower projects the benefits of the mandate of section 405 of the Public Utility Regulatory Policies Act of 1978 (PURPA) to provide simplified and expeditious licensing procedures for small hydroelectric power projects, consistent with the Act and other applicable laws. The common objective of both final rules is to ease the burden of applying for a license, particularly for those projects with a comparatively small installed capacity, by clarifying and consolidating the exhibits that must be filed and by extending the benefits of the "short-form" application requirement from licenses for projects of 1.5 megawatts or less to licenses for any water power project with an installed capacity of 5 megawatts or less. The Commission believes that these changes will have an impact on the non-Federal development of hydroelectric facilities, including development by small businesses and small governmental entities that may seek to build, own, and operate many of them; the impact of the revised requirements will primarily be the reduction of the regulatory and compliance costs associated with hydroelectric development.

Specifically, the major purpose of this rule, as proposed, is to "establish differing compliance . . . requirements . . . that take into account the resources available to small entities," and to "clarify, consolidate, or simplify compliance and reporting requirements . . . for small entities"—precisely the approach which the RFA seeks to encourage.[10] Applications for license for the kind of water power projects that would be covered by the procedures proposed in this docket number approximately 150 each year. Of these applications, possibly 75% are filed by entities that qualify as "small entities", including, within the meaning of section 601 of the RFA, municipalities under 50,000 population. The greatest simplification of the application requirements—applying the short-form licensing rule with its abbreviated initial statement and only four short exhibits to projects between 1.5 and 5 megawatts—will affect those projects for which small entities most frequently seek licenses.

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[8] 5 U.S.C. 601-612.

[9] *See* Footnote 7, *supra.*

[10] *See e.g.,* 5 U.S.C. 603(c) (1) and (2).

The Commission receives annually between 10 and 15 applications for license for the major unconstructed water power projects covered by the rule in Docket No. RM80-39. Between 50 percent and 60 percent of these applicants are "small entities", including municipalities. The Commission's responsibilities to protect lives, public health and safety, and the environment, and to ensure comprehensive development of the Nation's water resources, require that the filing requirements for such projects be generally more extensive than for projects with smaller installed generating capacities built at existing dams. Nevertheless, applicants for license for major unconstructed projects will be subject to greatly clarified requirements with fewer and better organized exhibits and fewer duplicative and unnecessary data requests. The Commission anticipates that it will receive under this rule, as it has under other revised applications rules, better and more complete applications which do not contain the applicant's subjective interpretations of the regulations. As a result, licensing will become a more efficient and less financially wasteful process.

The Commission considered various alternatives to the proposed rule which might help minimize any adverse economic impact on small entities. From the viewpoint of regulatory flexibility, the alternatives to the proposed rules are to leave the existing provisions intact, to further simplify the licensing regulations, or to tailor application requirements according to the type of applicant. The first would contradict the objectives of regulatory reform. The second, a further reduction in the amount of information requested in the exhibits, would seriously impair the Commission's ability to fulfill its responsibilities under its primary jurisdictional statutes and relevant environmental laws. The Fish and Wildlife Coordination Act, the Endangered Species Act, the Wilderness Act, the Wild and Scenic Rivers Act, the Clean Water Act, the National Environmental Policy Act (NEPA), the National Historic Preservation Act, and similar statutes, necessitate a certain circumspection in authorizing development of public water resources.

A third alternative is available to the Commission. Two kinds of short-form license provisions for facilities 5 megawatts and smaller could be established, one for applications for "small entities" within the meaning of the RFA, and another for applications filed by larger entities. As stated in the Initial Analysis, the Commission does not believe this represents a viable approach. The RFA encourages regulations which fit the scale of the business or governmental unit which is subject to regulation. However, in this instance, the information collected is related only to the nature and size of the proposed project, not the size or resources of the applicant. It is the project, not the small entity, that is the subject of regulation.

Relatively small entities commonly seek to develop major unconstructed or major modified projects, with all the attendant impacts of such projects. Those impacts and the relevant public interest concerns do not diminish according to the size of the applicant. NEPA, for example, does not enable the Commission to waive the Environmental Impact Statement requirement for actions that might significantly affect the quality of human environment based on who can bear the regulatory costs. Moreover, this alternative would create an unnecessary multiplicity of license application forms for projects 5 megawatts and smaller, and result in an undesirable proliferation of categories that would complicate, not simplify, hydroelectric regulation. In any event, the benefits of savings in time and money which derive from the shortform procedures should be equally available to all entities, small and large, which seek these licenses.

The Commission received some criticism of its Initial Analysis as it pertains to the proposed rule in Docket No. RM80-39. One commenter found the Initial Analysis inadequate in assessing the costs and benefits which the rule would confer on "small entities." The commenter suggested that the alternative of further reducing filing requirements was not considered. As a result of the Commission's alleged failure to comply with the RFA in these ways, the commenter asserts that small entities are confronted with a barrier to entry into the field of hydropower development.

The Commission has reviewed the rule in Docket No. RM80-39 in light of these comments and concluded that the concerns expressed are anticipated in the rule. The primary objective of the rule in that docket, as in this, is to provide regulatory relief. The license application requirements for major unconstructed projects are written in clear but detailed prose which may appear to constitute an overall increase in the volume of information requested despite the reduction in the number of the exhibits. This perception is fundamentally inaccurate. The amount of data requested overall is diminished under the final rule. The application requirements now include reference to the significant amount of information typically requested and obtained by individual requests after applications are found deficient. Another benefit of a highly explanatory application requirement is to minimize the element of subjective interpretation which arises from ambiguous or incomplete instructions. The degree of diminution of the requested information is admittedly not as great as in the Commission's revisions in Order Nos. 11, 54, and 59.[11] This is due not to any lack of commitment to regulatory reform but to the particular engineering and environmental characteristics of the construction and operation of major unconstructed and major modified projects in relation to the Commission's regulatory responsibilities under law.

"Small entities" are not distinguished from other license applicants in terms of the extent of the filing or consultation requirements which must be met. The Commission believes that such a distinction, which recognizes the relative abilities of applicants to comply, might be appropriate for other kinds of regulations but not for those which pertain to authorization to construct, operate, and maintain a particular kind of facility, especially when the statutory scheme of the Federal Power Act contemplates competition for a single development among different kinds of applicants and the utilization of public water resources.

Alternatives to the final rule have been considered and rejected, either because they would result in delays in the licensing process which are costly to applicants for license or because statutory requirements limit further reduction of the filing requirements for the kinds of projects licensed pursuant to the final rule in Docket No. RM80-39.

IV. Section-by-Section Analysis

The final rule primarily revises Subpart G or Part 4 and sets forth what is required of a non-Federal applicant seeking a license for development of a water power project 5 megawatts or less.

Applicability and definitions. § 4.60

This section states that §§ 4.60 and 4.61 apply to any application for either an initial or new license for a water power project with an installed generating capacity of 5 megawatts or less. The section defines "minor water power project", "new license", and "initial license". Under § 4.50(a) and

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[11] *See* Footnotes 1-3, *supra*.

§ 4.40(a), as revised in Docket No. RM80-39, an applicant for a major project with an installed capacity of 5 megawatts or less must use the abbreviated application requirements provided in §§ 4.60 and 4.61

Contents of application. § 4.61

This section contains the specific regulations governing the contents of the abbreviated application for license for water power projects with a total installed generating capacity of 5 megawatts or less. The requirements are embodied in the general instructions, an initial statement, and three lettered exhibits.

(a) *General instructions.* The general instructions prescribe the number of copies of the application that must be filed with the Commission, and explain the level of detail required of the applicant in describing the project. The applicant is required to consult with appropriate Federal, State, and local agencies with expertise in environmental matters and submit with its abbreviated application for license documentation of or a summary of the consultation process.

(b) *Initial statement.* The initial statement provides basic information, including the nature of the application, the names, addresses, and telephone numbers of the applicant and its authorized agents, the nature of the applicant, and the name and location of the project. A brief project description and construction dates are required, together with a list of any public lands or reservations affected by the project a copy of the applicant's water quality certificate or a copy of a letter from the applicant to the appropriate agency requesting the certification evidence of competence under State law, and information on other State requirements.

(c) *Exhibit A.* Exhibit A is new. It now contains the project description and mode of operation information formerly in the General instructions and the Initial Statement.

(d) *Exhibit E.* This exhibit provides a report on the environmental resources of the project and the impacts of the project on those resources. Applicants for license of uncontested or modified projects between 1.5 megawatts and 5 megawatts ("major") must file an Environmental Report as required under the Commission's regulations governing major unconstructed projects and major modified projects.[12] Applicants for license for projects with an installed capacity of 1.5 megawatts or less and for most major projects at existing dams must file a less extensive Environmental Report, as outlined in the proposed Exhibit E. The more stringent requirements are necessary for major unconstructed and major modified projects because there are greater impacts associated with the construction of dams and the creation of impoundments, or any subsequent significant increase in the size of an impoundment.

The environmental report is required to contain a description of the steps taken by the applicant in consulting with Federal, State, and local natural resources agencies, and the applicant must furnish copies of any letters containing the comments of those agencies or, where appropriate, other documentation of the consultation.

(e) *Exhibit F.* This exhibit consists of general design drawings of the principal project works. The drawings must show a plan, elevation, profile, and section of the dam structure and powerplant, but the drawings need not conform to the specifications of § 4.32 of the Commission's regulations. Instead, the exhibit must be a simple drawing, and may be displayed on smaller sheets.

(f) *Exhibit G.* The final exhibit is a map of the project. The map need not conform to the specifications of § 4.32. If the project is proposed to have an installed capacity of 1.5 MW or less, and will not occupy any public lands or reservations, a definitive project boundary need not be shown. All other projects must include a project boundary defined by contours, courses, and distances, or a public land survey, depending upon the project works involved.

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[12] *See* § 4.41(f) of Docket No. RM80-39.

V. Other amendments to the regulations

In addition the described amendments to §§ 4.60 and 4.61, the Commission further changes to the existing regulations. Section 4.31 is amended to reflect the nomenclature in §§ 4.60 and 4.61. In the rulemaking in Docket No. RM80-39, § 4.50(a), which now defines the applicability of the regulations for major projects—existing dam, requires use of the abbreviated application for license for any such project with a generating capacity of not more than 5 megawatts.

Section 16.12 is revised to reflect the nomenclature of §§ 4.60 and 4.61. Section 131.6, which prescribes the existing abbreviated application for license, is revoked, since the proposed rule contains a new application format that obviates § 131.6. Finally, § 375.308 is revised to omit the reference to § 131.6, which contains the existing short-form application requirements.

VI. Effective date

This final rule is effective December 14, 1981.

(Federal Power Act, as amended, 16 U.S.C. 792-828c; Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601-2645; the Department of Energy Organization Act, 42 U.S.C. 7101-7352; E.O. 12009, 3 CFR 142 (1978).)

In consideration of the foregoing, the Commission amends Parts 4, 16, 131, and 375 of Chapter I, Title 18, Code of Federal Regulations, as set forth below, effective December 14, 1981.

By the Commission.

Kenneth F. Plumb,
Secretory.

[¶ 30,310]

46 F. R. 57464 (November 24, 1981)

18 CFR Part 271

[Docket No. RM79-73; Order No. 188]

Final Rule Under Section 108 of the Natural Gas Policy Act Defining the Term "Produced"

November 16, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Commission by this final rule adopts, without change, an interim rule which defines the term "produced" as that term is used in the definition of "production days" in section 108(b)(3) of the Natural Gas Policy Act of 1978 (NGPA). (44 FR 66783, November 21, 1979.) Natural gas is "produced", within the meaning of section 108(b)(3) of the NGPA on (1) any day during which there is measurable production of natural gas from a well, and (2) any day during which a well is open to the line but is unable to produce measurable quantities of natural gas.

DATE: This rule is effective November 16, 1981.

FOR FURTHER INFORMATION CONTACT:

Randall Rich (202-357-8511), Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426

Marilyn Rand (202-357-8674), Dan White (202-357-8066), Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426

SUPPLEMENTARY INFORMATION: The Federal Energy Regulatory Commission (Commission) is amending § 271.803 by adopting a final rule to define the term "produced" as it is used in section 108(b)(3) of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3318), which defines the term "production day." For the purpose of determining "production day," gas is "produced" on (1) any day during which there is measurable production of natural gas from a well; and (2) any day during which a well is open to the line but is unable to produce measurable quantities of natural gas.

I. Background

Section 108 of the NGPA establishes a maximum lawful price for natural gas purchased from stripper wells, which at their maximum efficient rate of flow (MER) (*see* § 271.807), produce an average of 60 Mcf or less of nonassociated natural gas per production day during a preceding 90-day production period. Section 108(b)(3)(A) of the NGPA defines "production day" as:

> (i) Any day during which natural gas is produced; and (ii) any day during which natural gas is not produced if production during such day is prohibited by a requirement of State law or a conservation practice recognized or approved by the State agency having regulatory jurisdiction over the production of natural gas.

The Commission determined that certain shut-in or open valve wells that are incapable of producing and certain wells that produce on an irregular basis should be accounted for in defining the term "production day" and the term "produced" in section 108 of the NGPA. On November 9, 1979 pursuant to section 501(b) authority,[1] the Commission issued an interim interpretative regulation (44 FR 66783, November 21, 1979) defining, in § 271.803(e), the term "produced" as it is used in the definition of "production day" in section 108. Section 271.803(e) defined the term "produced" as follows:

(e) Natural gas is produced, within the meaning of section 108(b)(3) (A) and (B) of the NGPA:

(1) On any day during which there is measurable production of natural gas from a well, and

(2) On any day on which a well is open to the line but is unable to produce measurable quantities of gas.

This regulation provides a basis for wells that are either shut-in or open valve and are incapable of producing or that are producing on an irregular basis to qualify for stripper well status. The Commission invited public comment on the interim regulation.[2]

II. Summary of Public Comments

A. *Action by Pipelines and Operators Affecting Production.* Two comments focus on actions by pipelines and operators that would affect production rates. One commenter recommends that the Commission expand the definition of production day to include days when a well is shut-in due to actions by a pipeline.

The Commission specifically noted in the preamble to the interim rule that days on which gas is not produced for such reasons are not included in the definition of production day. We affirm that finding here because a well that is shut-in due to a pipeline's action would not be producing, attempting to produce, or shut-in to comport with state conservation practices as required by section 108(b)(3) of the NGPA.[3]

Along similar lines, a second commenter recommends that the Commission explicitly exclude days in which an operator increases the line pressure to enable a well to meet the production limitation for stripper wells. The commenter claims that operators will increase the line pressure to create a corresponding decrease in well production during a 90-day qualifying period. After a qualifying period at the stripper level has been established for the well, the line pressure will be decreased to allow increased production. The commenter suggests that this potential problem could be averted if the regulation required that production volume be measured at the historical pressure of the line into which the gas flows.

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[1] Section 501(b) of the NGPA, 15 U.S.C. 3411, authorizes the Commission "to define, by rule, accounting, technical and trade terms" used in the NGPA, so long as such definition is "consistent with the definitions set forth in [the] Act."

[2] The Commission invited requests for a public hearing. A public hearing was scheduled and subsequently cancelled by Commission notice issued January 2, 1980 because the only request for a hearing was withdrawn.

[3] Since the comments were filed in this docket, the Commission initiated a rulemaking to establish regulations governing stripper wells that overproduce as a result of temporary pressure buildup. Docket No. RM81-12, Interim Rule issued January 15, 1981 (46 FR 6901, January 22, 1981). The resulting rule provides that in certain cases, a well which would otherwise be disqualified can retain stripper well qualification if the increase in production is the result of pressure build-up which occurred when the well was temporarily shut-in.

The Commission agrees with the commenter that such manipulation of line pressure circumvents the intent of section 108. The Commission, however, has no reason to believe that this activity is prevalent and does not believe that it is presently necessary to deal with this explicitly in the regulations. Should a purchaser bring such a situation to the Commission's attention or should there be a series of disqualification and requalification filings for a single well, the Commission will take appropriate action.

B. *Expansion of Time Allowed to Establish Qualifying 90-day Production Period.* Another commenter suggests that the requirement in § 271.804(c) that the qualifying 90-day production period must occur sometime within the 180-day period immediately preceding the application filing date is unduly restrictive. The commenter suggests the 180-day period should be lengthened to cover, for example, five years prior to the filing date of the application. Where a compressor has been installed on a well within the last five years, the commenter asserts that the Commission should permit the operator to utilize the 90-day period immediately preceding installation of the compressor, or the Commission should permit the operator to demonstrate what the production would have been without the use of the compressor.

The Commission addressed this issue in footnote 6 in the preamble to the interim rule where it stated in part:

> Because the statute speaks in terms of *the* preceding 90-day production period, rather than *a* preceding 90-day production period, it appears that Congress did not intend that *any* 90-day production period become the basis for a stripper well determination. Instead, Congress apparently wanted the *most recent* 90-day production period before the date of application to be the basis for the determination. Accordingly, the Commission adopted § 271.804(c), which provides that the 90-day production period upon which the application is based must fall entirely within the 180 days prior to the date the application is filed. This regulation: (1) Resolves time problems caused by the necessity of collecting data from the field by giving producers up to 90 days to file an application with the jurisdictional agency after establishing a 90-day production period; (2) attempts to comply, in as practical a manner as possible, with the intent of Congress that the 90-day production period *nearest* to the application date be the period evaluated by the jurisdictional agency when it makes a determination. 44 FR at 66764.

The commenter's statement does not present any new information which would persuade the Commission to modify the regulation. To implement the commenter's suggestion would not comport with the purpose of section 108 of the NGPA to encourage production from marginal wells that might otherwise have been abandoned or might not have justified further expenditures to increase production. In situations where producers installed compressors prior to the passage of the NGPA, the producers evidently believed that such installation was cost-justified on the basis of the expected revenues at pre-NGPA prices. Thus, the Congress limited the stripper well qualification to wells producing at qualifying levels during the immediately preceding 90-day production period and not on some period several years before a compressor or other enhanced recovery technique [4] was used on the well.

III. Summary of the Rule

The interim rule is not amended by this order but is issued as a final rule. The rule provides a definition of "produced" as that term is used in section 108(b)(3) of the NGPA. It provides that gas is produced on any day during which there is measurable production and on any day during which a well is open to the line, even if it is unable to produce measurable quantities of gas.

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[4] Order No. 44, Docket No. RM79-73, issued August 22, 1979, (44 FR 49656, August 24, 1979).

IV. Effective Date

Because the interim regulation is not amended by this final rule and has been effective since November 9, 1979, good cause exists to waive the 30-day publication period otherwise required by section 553 of the Administrative Procedure Act, 5 U.S.C. 553(d). Accordingly, this final rule shall be effective November 16, 1981.

(Natural Gas Policy Act of 1978, (15 U.S.C. 3301–3432); Department of Energy Organization Act, (42 U.S.C. 7101 *et seq*) E.O. 12009, 42 FR 46267)

In consideration of the foregoing, the Commission amends Part 271 of Subchapter H, Chapter I, Title 18, Code of Federal Regulations, as set forth below, as a final rule effective November 16, 1981.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,311]

46 F. R. 57466 (November 24, 1981)

18 CFR Parts 271 and 274

[Docket No. RM81-25; Order No. 187]

Final Rule Under Section 108 of the NGPA Establishing Procedures for Operator Protests Regarding Stripper Well Natural Gas

November 16, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Commission by this final rule establishes procedures and filing requirements for operator protests of notices to disqualify stripper wells from the section 108 pricing category. When a stripper well over-produces, except under several limited circumstances, the operator and purchaser are required to file notices of disqualification. An operator can protest a notice of disqualification by following the procedures established by this rule.

DATE: This rule is effective January 12, 1982.

FOR FURTHER INFORMATION CONTACT:

Randall Rich (202–357–8511), Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426

Marilyn Rand (202–357–8674), Dan White (202–357–8066), Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426.

SUPPLEMENTARY INFORMATION: By this rule the Federal Energy Regulatory Commission (Commission) is amending its regulations in 18 CFR Parts 271 and 274 relating to natural gas produced from stripper wells under the Natural Gas Policy Act (NGPA) (15 U.S.C. 3301–3432). The amendment establishes procedures for filing and considering operator protests of notices of disqualification filed by their purchasers.

I. Background

Section 108 of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3318) prescribes the maximum lawful price for natural gas produced from stripper wells and the criteria for qualifying such wells. In Subpart H of Part 271 of its regulations, the Federal Energy Regulatory Commission (Commission) has established rules that implement section 108. Under these regulations, a well will qualify as a stripper well if, at its maximum efficient rate of flow, it produces no more than an average of 60 Mcf of nonassociated natural gas per production day during the qualifying 90-day production period. It will be disqualified if it produces in excess of that level unless the excess production is shown to be caused by application of a "recognized enhanced recovery technique", (*see* § 271.803), seasonal fluctuations (*see* § 271.804(d)), or temporary pressure build-up (*see* Docket No. RM81-12, Interim Rule, 46 FR 6901, January 22, 1981).

Section 271.805 requires the operator and purchaser to file notices of disqualification when a stripper well exceeds the natural gas production limitation. If the purchaser files a notice of disqualification and the operator does not agree, the operator can protest the notice by filing a motion contesting the notice of disqualification in accordance with § 271.805(b)(1)(i) of the regulations.

The regulations currently do not prescribe the filing requirements for the operator's motion to contest or the procedures for considering and acting upon the motion. The Commission issued a Notice of Proposed Rulemaking on April 3, 1981 for the purpose of amending the regulations to eliminate this procedural deficiency by proposing filing requirements and protest procedures for public comment.[1]

(46 FR 21192, April 9, 1981)

II. Comment Analysis

Two comments were filed in this docket. One generally supports the Commission's initiative in this rulemaking but criticizes the provision in § 271.806(b) of the proposal that requires the jurisdictional agency to treat the motion in accordance with the provisions of Subpart A of Part 274 as if it were an application for an initial well category determination. The commenter interprets that provision as requiring the operator to refile all the documents required for an application for well category determination. Based on that interpretation, the commenter asserts that proposed § 271.806(b) required the filing of duplicative materials, causing unnecessary delay.

That interpretation is not correct. The proposed language in § 271.806(b) provides:

> A jurisdictional agency shall treat a motion contesting a notice of disqualification under § 271.805(b)(1)(i) as if it were an application for initial determination and shall comply with *applicable provisions* of Subpart A of Part 274 of this chapter (italic added).

Subpart A of Part 274 establishes the general provisions regarding initial determinations by jurisdictional agencies and the procedures for providing the Commission notice of such determinations and an opportunity to review them. Subpart A does not prescribe any filing requirements. Subpart B of Part 274 imposes filing requirements for initial jurisdictional agency well category determinations. This final rule adds other filing requirements to § 274.206(f) of Subpart B for the operator's motion to contest.

The Commission notes that the language in proposed § 271.806(b) quoted above serves a similar purpose and is parallel to existing language in § 271.806(a) that governs procedures for other petitions relating to stripper wells. Section 271.806(a) has not been implemented as the commenter would interpret that provision.

The second commenter states that it generally supports the proposed protest procedure but requests a clarification by the Commission on whether the operator may continue to collect the section 108 price during the pendency of the protest proceeding without filing for interim collection under Part 273.

Section 271.805(d) of the existing regulations permits the operator to continue to collect the section 108 price subject to refund from the last day of the production period to which the notice of disqualification applies if the motion to contest is filed within the appropriate time period. If the motion is not filed within the appropriate time period, the right to collect the section 108 price terminates as of the last day of the disqualifying production period. If a motion is later filed, the operator may commence collection of the section 108 price subject to refund from the date the motion is filed. Therefore, § 271.805(d) already provides for interim collections during the pendency of the protest proceeding.

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[1] The Commission invited requests for a public hearing but no requests were received. Therefore, no hearing was held.

However, in response to this comment, an incorrect reference to paragraph (b) in § 271.805(a)(3) (regarding termination of the right to collect the section 108 maximum lawful price) is amended to refer to paragraph (d) in accordance with which the operator may continue to collect the section 108 price.

III. Summary of Amendments to the Regulations

Section 271.806 (b) is amended by inserting the proposed paragraph providing that the jurisdictional agency shall treat a motion protesting a notice of disqualification as if it were an application for initial determination and shall comply with the applicable provisions of Subpart A of Part 274. Conforming changes are made to §§ 271.805 and 271.806.

Section 274.206 is amended by the addition of proposed paragraph (f), which provides the filing requirements for a motion to contest. They include, in substantial part: (1) A reference to the initial determination qualifying the well for stripper status; (2) a reference to the notice of disqualification; and (3) a statement summarizing the reasons why the well should not be disqualified, accompanied by any supporting documentary evidence.

IV. Effective Date

For the reasons discussed above, the Commission makes final the regulations set forth below, effective January 12, 1982.

(Natural Gas Policy Act of 1978, (15 U.S.C. 3301–3432); Department of Energy Organization Act, (42 U.S.C. 7101, *et seq.)*; E.O. 12009, 42 FR 46267)

In consideration of the foregoing, the Commission amends Parts 271 and 274, Subchapter H, Chapter I, Title 18, of the Code of Federal Regulations, as set forth below effective January 12, 1982.

By the Commission.
Kenneth F. Plumb,
Secretary.

[¶ 30,312]

46 F. R. 57467 (November 24, 1981)

18 CFR Part 271

[Docket No. RM81-6; Order No. 186]

Final Rule Under Section 108 of the Natural Gas Policy Act; Continuing Qualification

November 16, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Commission by this rule amends § 271.805 (18 CFR Part 271) in paragraphs (c) and (d) regarding the 30-day period within which an operator protest must be filed in order that the operator may continue to collect the section 108 price during the pendency of disqualification proceedings. This rule enlarges the filing period by 30 days.

DATE: This rule is effective as a final rule November 16, 1981.

FOR FURTHER INFORMATION CONTACT:

Randall Rich (202–357–8511), Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426

Marilyn Rand (202–357–8674), Dan White (202–357–8066), Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426

SUPPLEMENTARY INFORMATION: In Subpart H of Part 271 of its regulations, the Federal Energy Regulatory Commission (Commission) established rules implementing section 108 of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3318). Section 108 sets a maximum lawful price for natural gas from stripper wells. Stripper wells are wells that produce nonassociated gas at very low production rates. To qualify for the section 108 stripper well maximum lawful price a well must produce within the prescribed production limitation and can be disqualified on the basis of overproduction. By this rule the Commission is amending § 271.805, which establishes, in part, procedures an operator must follow to collect the section 108 price during the pendency of disqualification proceedings.

I. Background

The NGPA defines a stripper well as one that produces, at its maximum efficient rate of flow, no more than an average of 60 Mcf of nonassociated natural gas per production day during the preceding 90-day production period. If a well's production exceeds this limitation, the well will be disqualified unless the overproduction is shown to be caused by application of a "recognized enhanced recovery technique" (*see* § 271.803) or seasonal fluctuations (*see* § 271.804(d)). If such circumstances cause the overproduction, the well will continue to qualify as a stripper well.[1]

When a well overproduces, however, the Commission's regulations in § 271.805, as they existed prior to the issuance of the interim rule in this docket, required that the operator and purchaser give notice of the disqualification to the Commission and the appropriate jurisdictional agency within 90 days after the end of the production period (90 days or, in the case of a seasonally affected well, 12 months) in which the overproduction occurs. Under § 271.805(d), the operator of such a well could continue to collect the stripper well price (subject to refund) after the disqualification notice was served, if, within 30 days, the operator filed with the jurisdictional agency a petition for a determination that the increased production is the result of one of the above-described circumstances or if the operator filed a motion contesting the notice of disqualification filed by the purchaser. If timely action was not taken by the operator to oppose the notice of disqualification, the well was disqualified and ceased to be eligible for the section 108 price as of the last day of the disqualifying period.

On November 25, 1980, the Commission issued an interim rule in this docket amending § 271.805. (45 FR 80273, December 4, 1980.) Under the interim rule, a motion or petition filed within the 30-day period still permits the operator to continue to collect the section 108 price after the last day of the disqualifying period. However, failure to file timely does not permanently deprive the operator of the right to collect this price; it merely terminates the operator's right to collect the section 108 price from the last day of the disqualifying period until the date the motion or petition is later filed.

II. Comment Analysis

In the interim rule, the Commission requested interested persons to submit comments.[2] Two comments were received.

A. *Extension of the 30-day period for filing motion or petition opposing the disqualification.* One commenter suggests that the 30-day period for filing be extended to 60 or 90 days in order to provide small producers sufficient time, in view of their manpower constraints, to prepare and file the motion or petition. The commenter argues that, particularly in the case of small producers, it is important that they are able to make a timely filing to protect their right to collect the section 108 price.

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[1] Another circumstance the Commission has recognized as causing unnecessary disqualification and requalification of stripper wells is overproduction caused by temporary shut-in of the well. On January 15, 1981, the Commission issued for public comment an interim rule which permits a well to continue to qualify for stripper status even though it experiences overproduction as a result of being temporarily shut-in. (46 FR 6901, January 22, 1981.)

[2] The Commission invited requests for a public hearing but no requests were received. Therefore, no public hearing was held.

The Commission agrees with the commenter that small producers who have limited manpower may not be able to file within the 30-day period. In view of such limitation, the Commission agrees to extend by 30 days the time within which to file the appropriate pleading and clarifies as discussed below when that period shall run.

The Commission is aware that some operators are confused as to the date the motion or petition must be filed in the event the notice of disqualification is filed late. Operators have applied the rule in § 271.805 as if the running of the filing period were contingent on the date the notice of disqualification was actually served regardless of whether it is timely filed. This does not comport with the Commission's intention that both the notice of disqualification and the operator's motion or petition be filed within fixed time periods after the last date of the disqualifying production period. The Commission believes that the confusion about the date for filing the operator's motion or petition will be eliminated if the filing date for the operator's motion or petition were fixed a certain period of time after the last day of the disqualifying period, rather than after the date the notice of disqualification is served. With the additional 30 days provided herein, the total period is 150 days. As revised herein, § 271.805 now requires that the operator file the motion or petition within 150 days after the last day of the disqualifying period in order to continue to collect the section 108 price. If the operator fails to file within that period, the right to collect the stripper well price terminates on the last day of the disqualifying period until the date the filing is made.

B. *Filing of Notice of Disqualification.* Another commenter supports the interim rule but suggests with regard to the filing of the notice of disqualification that the Commission should place less burden on the purchasers than on the operators for filing such notice. The commenter asserts that in many circumstances the purchaser cannot know the exact production of every stripper well connected to the line without inquiring of the operator. The commenter suggests that language be added to § 271.805 to require that the purchaser file the notice only if it acquires pertinent information in the ordinary course of business.

The Commission has previously considered and rejected the commenter's argument when final regulations were issued for section 108 in Order No. 44, Docket No. RM79-73. (44 FR 49656, August 24, 1979.) In the preamble to Order No. 44, the Commission stated that both the operator and the purchaser are obligated to report any increase in gas production above the prescribed production limitation. Thus, both the operator and pipeline must monitor the production in order to make the necessary report when overproduction occurs. The commenter did not present any new information that would persuade the Commission to reconsider its prior decision in Order No. 44.

III. Summary of Amendments to the Regulations

Section 271.805(c) is amended to provide that the operator must file a motion or petition to oppose disqualification within 150 days of the last day of the 90-day or 12-month disqualification production period in order to continue to collect the section 108 price from the last day of the disqualifying period.

Section 271.805(d) is amended to conform with revised § 271.805(c).

IV. Effective Date

This final rule relieves restrictions previously placed on applicants under the Commission's regulations and therefore the 30-day notice requirement of section 553(d) of the Administrative Procedure Act, 5 U.S.C. 553(d), is waived. The Commission promulgates as final the amendments set forth below effective November 16, 1981.

(Natural Gas Policy Act of 1978, (15 U.S.C. 3301–3432); Department of Energy Organization Act, (42 U.S.C. 7101, *et seq.*); E.O. 12009, 42 FR 46267)

In consideration of the foregoing, the Commission amends Part 271 of Subchapter H, Chapter I, Title 18, Code of Federal Regulations, as set forth below, and issues such amendments as final rules effective November 16, 1981.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,313]

46 F. R. 57469 (November 24, 1981)

18 CFR Part 282

Incremental Pricing

[Docket No. RM81-17; Order No. 189]

Definition of Agricultural Use

Issued: November 16, 1981.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Commission by this rule amends the definition of "agricultural use" in § 282.202(a)(1) of the Commission's incremental pricing regulations. (18 CFR Part 282). Section 282.202(a)(1) lists agricultural uses of natural gas that are exempt from incremental pricing. The amendment adds other products and processes to the list of processes that are already exempt from incremental pricing surcharges.

DATE: This rule is effective November 16, 1981.

FOR FURTHER INFORMATION CONTACT:

Robert Fleishman, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, 202–357–8511.

Alice Fernandez, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, 202–357–9095.

SUPPLEMENTARY INFORMATION: The Federal Energy Regulatory Commission (Commission) is amending its regulations on incremental pricing (18 CFR Part 282) under Title II of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3301–3432). Specifically, the list of agricultural uses of natural gas set forth in § 282.202(a)(1) that are exempt from incremental pricing surcharges is amended by the addition of products and processes.

I. Background

Title II of the NGPA requires the Commission, within certain guidelines, to institute and administer an incremental pricing program. The program is designed to pass through, by surcharge, a portion of the increases in the wellhead prices of natural gas allowed under Title I of the NGPA to certain industrial facilities that use natural gas as a boiler fuel. Pursuant to section 206(b)(1) of the NGPA, however, incremental pricing does not apply to any "agricultural use" of natural gas. Section 206(b)(3) defines "agricultural use" as follows:

> (3) Agricultural Use Defined.—For purposes of this subsection, the term "agricultural use", when used with respect to natural gas, means the use of natural gas to the extent such use is—
>
> (A) for agricultural production, natural fiber production, natural fiber processing, food processing, food quality maintenance, irrigation pumping, or crop drying; or
>
> (B) as a process fuel or feedstock in the production of fertilizer, agricultural chemicals, animal feed, or food.

The statutory term "agricultural use" has been defined in § 282.202(a)(1) of Part 282 of the Commission's regulations (18 CFR Part 282) through Commission action in several rulemaking dockets. The term is defined by a list of industrial products and processes including references to Standard Industrial

Classification Codes (SIC codes) where applicable.

In Docket No. RM79–14, the Commission proposed the definition of "agricultural use". The proposed definition listed certain uses of natural gas that were certified by the Secretary of Agriculture as "essential agricultural uses" pursuant to section 401 of the NGPA.[1] In the final rule, the Commission expanded this list to include the processing and finishing of natural fiber by the textile industry[2] and, on rehearing of the final rule, added wood processing.[3]

Subsequently, rulemaking dockets were opened to consider petitions that requested the Commission to add other products and processes to the agricultural uses listed in § 282.202(a)(1). In Order No. 114 issued in Docket No. RM80–48,[4] the Commission added the following products and processes to the list: the manufacture of hardboard, man-made cellulosic fibers, food preservative butylated hydroxanisole, food-grade waxes (food containers), metal shipping containers (food related), naturally occurring vitamins, the processing of cotton linters, and wood preserving.

In this docket, the Commission is considering a broad range of uses submitted in petitions and as comments to the rulemaking. The Commission issued a Notice of Proposed Rulemaking on April 20, 1981 (46 FR 23487, April 27, 1981) to consider a petition filed by Peter Cooper Corporations (Peter Cooper), which would amend § 282.202(a)(1) to include the manufacture of glue, gelatin, and nitrogenous fertilizer, and a request filed by Hercules Incorporated (Hercules) for an interpretation that § 282.202(a)(1) includes the manufacture of carboxy methyl cellulose (CMC).[5]

II. Summary of Comments

Fifteen comments[6] were received in this docket. All but one of the commenters either supported the Commission's proposal as issued or recommended that other industrial products or processes be added.

The Commission may add other uses to § 282.202(a)(1) if they satisfy one of the categories of agricultural uses in NGPA section 206(b)(3). Most of the commenters relied on one or more of four categories described in section 206(b)(3)(A) (*i.e.* agricultural production, natural fiber processing, food processing, and food quality maintenance) to describe their products or processes. In addition to glue, gelatin, and carboxy methyl cellulose proposed in the notice, this rulemaking considers the following uses suggested by the commenters:

- The production of nitrogenous fertilizer from tankage (this process was considered in the notice and the

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[1] Proposed Regulations Implementing the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978, Docket No. RM79–14, issued June 5, 1979 (44 *Fed. Reg.* 33099, June 8, 1979). See also Docket No. RM80–75, Interim Rule, issued October 6, 1980 (45 *Fed. Reg.* 67276, October 9, 1980); Order granting partial stay, issued October 23, 1980 (45 *Fed. Reg.* 76661, November 20, 1980); Order amending stay, issued April 23, 1981 (46 *Fed. Reg.* 25599, May 6, 1981).

[2] Docket No. RM79–14, Order No. 49, issued September 28, 1979 (44 FR 57726, October 5, 1979).

[3] Docket No. RM79–14, Order No. 49–A, issued December 27, 1979 (45 FR 767, January 3, 1980).

[4] Docket No. RM80–48, Notice of Proposed Rulemaking issued April 10, 1980 (45 FR 25825, April 16, 1980); Final Rule (Order No. 114), issued December 5, 1980 (45 FR 82915, December 17, 1980); Order No. 114–A, issued January 29, 1981 (46 FR 11612, February 11, 1981).

[5] Commission Staff advised Hercules that it would be necessary to amend the regulations to include a SIC code to cover such manufacture since § 282.202(a)(1) could not be construed to cover Hercules' manufacture of CMC. Hercules agreed that its request for interpretation should be treated as a request for a rulemaking and included in this docket.

[6] Comments were filed in this docket by the Department of Agriculture, Peter Cooper, Hercules, Buckeye Cellulose Corporation, Humko Chemical, Reichhold Chemicals, Inc., Glass Packaging Institute, Stauffer Chemical Corporation, Morton Salt, W. R. Grace & Co., Kokomo Gas Company, the Fertilizer Institute, Celanese Plastics and Specialties Company, and Peoples Gas Light and Coke Company. An informal public hearing was held on Tuesday, June 9, 1981. The Association of Jigg Dyers presented an oral statement at the hearing but did not file written comments.

Commission requested additional information about the process)

- The production of cross-linked sodium carboxy methyl cellulose from wood pulp and processed cotton linters
- The dyeing and finishing of man-made fibers
- The production of fatty chemicals
- The production of gum and wood chemicals
- The production of metal crowns and closures
- The production of monosodium glutamate
- The production of food-grade and animal feed salt
- The processing of guar beans
- The production of fuel-grade alcohol

A. Uses Considered in the Proposal—Production of Glue, Gelatin, Nitrogenous Fertilizer, and Carboxy Methyl Cellulose.

Gelatin. In the April 20th notice, the Commission proposed to amend the definition of agricultural use in § 282.202(a)(1)(iii) to include under SIC Code 2899[7] the production of gelatin from animal hides by natural fiber processing but solicited comments that would detail the stages in the production of gelatin so that it could determine whether the animal hides are converted to some intermediate material before being converted to gelatin. If there were an intermediate product, not all of the stages of the process would qualify as natural fiber processing.

One company that produces gelatin submitted comments demonstrating that there is no stage in the process at which an intermediate finished product exists. Comments filed by the Department of Agriculture support the producer's conclusion.

The Commission believes, in view of these comments and information submitted in the petition filed by Peter Cooper, that the processing of gelatin from animal hides represents a series of closely-linked steps in the conversion of the hides to gelatin and concludes that all of the stages of such process are natural fiber processing. Accordingly, the Commission amends § 282.202(a)(1)(iii) to include SIC code 2899 for this process.

One commenter (a producer of gelatin) also asserted that the production of gelatin is a food processing use because the gelatin it produces is an ingredient in the production of gelatin desserts. Since the Commission has decided to exempt the natural gas used in the production of gelatin as natural fiber processing, it is not necessary to reach the food processing question.

Glue. Commenters supported the proposal to amend § 282.202(a)(1)(iii) to include the production of glue under SIC Code 2891 because it involves the processing of animal hides and, as such, qualifies as natural fiber processing. The Commission, again, solicited comments that detail the stages in the production of glue so it could determine which stages would quality as natural fiber processing. In response to the Commission's inquiry, a commenter demonstrated that production of glue, like gelatin, involves no intermediate finished product of the animal hides. The Department of Agriculture supported that conclusion.

For the same reason expressed above regarding gelatin, the Commission concludes that the entire process for producing glue from animal hides is natural fiber processing. The Commission, therefore, amends § 282.202(a)(1)(iii) to include SIC Code 2891 for the production of glue from animal hides.

Nitrogenous Fertilizer. In the April 20th notice, the Commission did not propose to include nitrogenous fertilizer that is derived from tankage, a product of the processing of animal hides.[8] The

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[7] SIC Code 2899 is presently listed as an exempt use, but is limited to "chemical cotton-processed cotton linters only"

[8] One company that produces nitrogenous fertilizer stated that its use of natural gas to produce nitrogenous fertilizer should be exempt as an "agricultural use" under section 206(b)(3)(A) of the NGPA because it uses natural gas as boiler fuel and not as process fuel or feedstock under section 206(b)(3)(B).

Commission, however, requested comments on the natural fiber processing use and its preliminary conclusion that tankage is not substantially comprised of natural fiber.

Regarding the natural fiber processing use, one commenter demonstrated that tankage is comprised of 90 percent animal hair and its presence is essential to the production of nitrogenous fertilizer.

Based upon the information submitted by this commenter and the Department of Agriculture, the Commission now concludes that tankage consists substantially of a natural fiber, animal hair, and that the processing of tankage into nitrogenous fertilizer is natural fiber processing rather than merely the processing of a residue of the natural fiber. Accordingly the Commission amends its regulation in § 282.202(a)(1)(iii) to include SIC Code 2873 for the production of nitrogenous fertilizer from natural fiber.

Carboxy methyl cellulose. The Commission proposed to include the production of carboxy methyl cellulose (CMC) from wood pulp as natural fiber processing but requested comments on whether the production of CMC from processed cotton linters is also natural fiber processing.

During a public hearing held on Tuesday, June 9, 1981 in this docket one commenter that produces CMC demonstrated the similarities in the production of CMC from processed cotton linters and the production of rayon, acetate, and tri-acetate from wood pulp already approved for inclusion in § 282.202(a)(1)(iii) in Order No. 114.[9] The commenter explained, at the hearing, that the first stage in the production of rayon, acetate, and tri-acetate and CMC involves the separation of wood and cotton linters from their organic binders (lignins and rosins) and that the second stage involves only the modification of the cellulose molecules to give the respective end products their desired characteristics.[10]

Another commenter made the same recommendation for CMC and further recommended that the production of cross-linked carboxy methyl cellulose (CLD-2) from processed cotton linters and wood pulp be included in § 282.202(a)(1)(iii) as natural fiber processing. That commenter explained that the CLD-2 produced from wood pulp and processed cotton linters involves similar processing steps and the same ingredients, except in different molecular ratio, as those involved in the production of CMC. In the processing of CLD-2, the first step involves the separation of the cellulose fibers from organic binders and the second step involves a modification of the cellulose fibers, albeit a different modification than in the production of CMC, to give the fibers the desired properties.

Based upon these comments, the Commission concludes that processed cotton linters are natural fiber.[11] This finding is consistent with the Commission's determination in Docket No. RM80-48, that the processing of wood pulp is natural fiber processing. Therein, the Commission stated, "the manufacture of cellulosic man-made fibers (SIC Code 2823) involves the processing of pulp (cellulose), a fibrous substance derived from wood, into man-made fibers such as rayon, acetate, and tri-acetate." The Commission concludes, here, that processed cotton linters, a fibrous substance derived from cotton, are natural fiber.

Based upon this finding, the Commission concludes that the production of CMC from processed cotton linters and CLD-2 from wood pulp and processed cotton linters are natural fiber processing. The Commission amends its regulation in § 282.202(a)(1)(iii) to include SIC Code 28697 for CMC and CLD-2 produced from wood pulp and processed cotton linters.

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[9] See note 4 *supra.*

[10] Rayon, acetate, and tri-acetate are the ester derivatives of cellulose and an acetic acid radical. CMC is the ether derivative of cellulose and a chloro-acetic acid radical.

[11] One commenter stated inaccurately that the Commission has already determined in Order No. 114, Docket No. RM80-48, that processed cotton linters are natural fibers. In that order, the Commission determined that cotton linters are natural fibers but did not make the same finding for processed cotton linters.

Argument Against Including Proposed Uses

One commenter argued that none of the proposed processes (glue, gelatin, and CMC) qualifies as an agricultural use because each involves the processing of a residue of natural fiber, rather than the natural fiber itself.

The Commission disagrees with the commenter's statement. The Commission has included uses of natural gas in the category of natural fiber processing if it is demonstrated that they involve the processing of natural fiber. In Order No. 114, the Commission determined that the production of man-made fibers, rayon, acetate, and tri-acetate, from wood pulp or cotton linters, involves the processing of natural fibers. These processes isolate cellulose, a natural fiber, from the wood pulp or cotton linters and then chemically treat the cellulose fibers. The same process is used to produce CMC and is similar to the processing of glue and gelatin, being considered in this rulemaking. Each of these processes qualifies as natural fiber processing because each involves the processing of a natural fiber whether it be animal hides, cotton linters, or wood pulp.

B. Additional Uses Suggested by Commenters

Dyeing and Finishing of Man-Made Fibers. One commenter requested that the Commission exempt the use of natural gas to process, by dyeing and finishing, rayon, acetate, and tri-acetate on the basis that it is natural fiber processing.

In Order No. 114, the Commission exempted from the incremental pricing surcharge natural gas that is used in the production of man-made, cellulosic fibers. The Commission based the exemption on the finding that the production of man-made, cellulosic fibers is natural fiber processing. In that order, the Commission also considered the extent to which the further processing of the man-made fibers is also an agricultural use but determined that such processing did not constitute natural fiber processing. The commenter did not present any new information at the June 9th hearing that would lead the Commission to reconsider its decision in Order No. 114 regarding the further processing of cellulosic, man-made fibers. Therefore, the Commission declines to exempt the use of natural gas to process rayon, acetate, and tri-acetate.

Processing of agricultural products and agricultural by-products into fatty chemicals that are used in food, textile and pharmaceutical products. One commenter requested the Commission to expand the list of agricultural uses in § 282.202(a)(1)(iii) to include the processing of agricultural products and by-products into fatty chemicals, particularly fatty acids. The commenter asserted that its conversion of raw materials to fatty chemicals is both agricultural production and natural fiber processing and that its products are essential to food quality maintenance and food processing.

Fatty chemicals are produced by the commenter from raw materials, including tallow, tall oils, fish oils, and vegetable oils.[12] These raw materials are transformed into fatty acids by hydrogenation (the addition of hydrogen atoms to the molecules), splitting in a continuous pressure-splitting tower, and distillation.

The Commission has previously rejected a request to have the above-described processes categorized as agricultural uses on the basis that they are not food processing and natural fiber processing. In Docket No. RM80-48, the Commission stated that:

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[12] Tallow is the rendered fat from cattle; tall oils are a by-product of wood pulp. Fish oils are derived from herring or menhaden. Vegetable oils are derived from rapeseed, crude soya, crude coco, and palm oil.

> The described processes are too far removed from the food chain to qualify as agricultural uses. Although the raw materials which are processed may be agricultural in nature, the processing of these materials does not constitute "food processing" or "natural fiber processing".

In view of its prior decision and the fact that no new information has been submitted, the Commission rejects the present request to have these processes included in § 282.202(a)(1) as food processing, natural fiber processing, and agricultural production.

The commenter also made an additional argument, not considered in Order No. 114, that a small percentage of its products are used as food additives and as such are used in food quality maintenance. However, the products that are included in the food quality maintenance category of § 282.202(a)(1) are essentially food-related packages and containers made from metal, glass, and plastic. The only chemical included in § 282.202(a)(1) is butylated hydroxyanisole (BHA), a well-known food preservative, approved for the category of food quality maintenance in Order No. 114. The fatty acids that the commenter produces, unlike BHA, are not food preservatives. Rather, as described by the commenter in comments filed in Docket No. RM80-48, they belong to "a class of products known as chemical intermediates * * * which are used by other chemical processers in producing plastics, lubricants, detergents, food emulsifiers, pharmaceuticals, and textiles."[13]

The Commission concludes that fatty chemicals do not preserve the quality of food but are chemical intermediates in the processing of food additives which may or may not contribute to food quality maintenance. Therefore, the Commission rejects the request to include these products in § 282.202(a)(1).

Production of rosin, turpentine, resins, and fatty acids. One commenter requested that the Commission expand the list in § 282.202(a)(1)(iii) to include SIC Code 2861 for the production of rosin, turpentine, resins, and fatty acids. The commenter stated that its production of such substances involves the processing of wood and constituent elements of wood into intermediate and end products and, therefore, is natural fiber processing. In one of its operations, the commenter processes wood stumps mechanically and chemically into wood chips and then processes the wood chips further by mixing the chips with petroleum solvents to produce rosin, turpentine, and pine oil.

The Commission believes that the processing of wood by mechanical and chemical means is natural fiber processing and that the natural gas used in these processes should be exempt from incremental pricing surcharges. The Commission amends § 282.202(a)(1)(iii) to include SIC Code 2861 for the processing of wood into rosin, turpentine, and pine oil.

In other operations, the commenter upgrades rosin and turpentine into paper "sizes", a substance that is sold to paper mills, and into various types of resins sold for use by others in the production of chewing gum, food-grade beverages, container coatings, and adhesives. Tall oil, a soap derived from wood supplied by pulp mills, is also processed, by distillation, into rosin, fatty acids, and paper "sizes".

The Commission rejects the request to include the processing of tall oil, rosin, and turpentine as natural fiber processing because none of these products is fibrous in nature or could be considered a natural fiber.[14]

Manufacture of metal crowns and closures. One commenter requested that the Commission include the manufacture of metal crowns and closures, such as bottle caps and jar tops for food containers, in the list of agricultural uses in § 282.202(a)(1)(ii). This use was certified by the Secretary of Agriculture as an "essential agricultural use". (45 FR 5297, January 23, 1980.)

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[13] The fact that such fatty chemicals are chemical intermediates is supported by a statement the commenter made in an application for adjustment, Docket No. SA80-72, wherein the applicant stated that it produces stearic acid that is further processed by others into stearic lactate, a food emulsifier, that is used in the baking industry.

[14] The processing of tall oil into fatty acids has previously been rejected by the Commission in Order No. 114.

The Commission has already included manufacture of "food-related metal cans, glass jars, and paper cartons" in § 282.202(a)(1)(iii) under food quality maintenance. Based upon consideration of the Secretary's determination and the comments filed in this docket, the Commission believes that metal crowns and closures that are part of the food container in its final form are essential for maintaining the quality of the enclosed food. The Commission amends § 282.202(a)(1)(ii) to include the manufacture of metal crowns and closures as an agricultural use of natural gas.

Monosodium glutamate. One commenter requested that the Commission expand § 282.202(a)(1)(iii) to include SIC Code 2869 for the production of monosodium glutamate (MSG) because it constitutes food processing. The commenter manufactures MSG from molasses by mixing the molasses with ammonia, sodium hydroxide, and trace nutrients and harvesting and refining the resulting culture by adding hydrochloric acid and sodium hydroxide to produce MSG. MSG is sold to food processers who use it in canned and prepared foods; it is also sold in food stores as a food flavor enhancer.

The Commission concludes that the production of MSG is food processing within the meaning of agricultural use in § 282.202(a)(1)(iii). MSG is a food seasoning akin to spice (SIC Code 2099) that is already exempt from incremental pricing surcharges as food processing. The Commission concludes that the production of MSG should also be included in the regulations as food processing. Accordingly, the Commission amends § 282.202(a)(1)(iii) to include SIC Code 2869 for MSG only.

Food-grade salt for human consumption only. A commenter requested that the Commission include in the regulations the processing and production of salt for food for human consumption and for animal feed.

The Commission concludes, for the same reasons as stated in its discussion of MSG, that food-grade salt for human consumption is a food seasoning, akin to a spice, and its production qualifies as food processing. Accordingly, the Commission amends § 282.202(a)(1)(iii) to include SIC Code 2899 for food-grade salt for human consumption only.

The boiler fuel use of natural gas in the production of feed-grade salt is not an agricultural use. Section 206(b)(3)(B) of the NGPA limits the agricultural use of natural gas for animal feed production to the process or feedstock use of the gas.[15]

Processing of guar beans. A commenter requested that SIC Code 2899 be expanded to include processing of guar beans as natural fiber processing on the basis that the processing of guar beans is analogous to the processes already included in § 282.202(a)(1) such as cotton ginning, leather tanning and finishing, and the processing of wood pulp and cotton linters. The commenter explained that guar beans are processed into a powder-like form for use in a large variety of applications as a gelling and thickening agent.

When the Commission considers whether a process is "natural fiber processing", it considers whether the material to be processed is fibrous in nature. The Commission believes that the processing of guar beans is not like the processing of cotton linters, which are the fibers adhering to the seeds after ginning, but is the processing of a nonfibrous substance. Therefore, the Commission concludes that the commenter's request for exemption should be denied as the processing of guar beans does not constitute the processing of a natural fiber.

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[15] However, the Commission notes that a rule exempting this use was recently issued in Docket No. RM80-18 (46 *Fed. Reg.* 50060, October 9, 1981). The rule provides an exemption from incremental pricing for natural gas used as boiler fuel for the production of fertilizer, agricultural chemicals, animal feed and food pursuant to section 206(d) of the NGPA. This is not an "agricultural use" exemption but rather a special exemption promulgated under the Commission's authority to establish additional categories of exemptions, subject to Congressional review.

Production of fuel-grade alcohol. One natural gas distributor requested that new plants using natural gas for processing grain into fuel-grade alcohol be exempted from incremental pricing surcharges. This comment would be properly considered in Docket No. RM80-64.[16] Therefore, the Commission will make the comment a part of the record in that docket.

III. Summary of Amendments to the Regulations

For the reasons stated above, the Commission amends § 282.202(a)(1)(ii) and (iii) of its regulations wherein agricultural uses exempt from incremental pricing are listed by adding the following uses:

1. In § 282.202(a)(1)(ii) under Food Quality Maintenance—Food Packaging, "3466 Metal Crowns and Closures (food related only)".

2. In § 282.202(a)(1)(iii) under Food Processing:

(a) "SIC Code 2869 Industrial Organic Chemicals, not elsewhere classified (monosodium glutamate only)"; and

(b) "SIC Code 2899 Chemicals and Chemical Preparations, not elsewhere classified (food-grade salt only)".

3. In § 282.202(a)(1)(iii) under Natural Fiber Processing:

(a) "SIC Code 2861 Gum and Wood Chemicals (the production of rosin, turpentine and pine oil from wood stumps and wood chips only)";

(b) "SIC Code 28697 Miscellaneous Acyclic Chemicals and Chemical Products, Excluding Urea (the production of carboxy methyl cellulose from wood pulp and processed cotton linters only; the production of cross-linked sodium carboxy methyl cellulose from wood pulp and processed cotton linters only)";

(c) "SIC Code 2873 Nitrogenous Fertilizer (the production of nitrogenous fertilizer from tankage substantially consisting of natural fiber)".

(d) SIC Code 2891 "the production of glue from animal hides, natural fiber processing only".

(e) SIC Code 2899 is expanded to include "the production of gelatin from animal hides, natural fiber processing only".

The amendments adopted in this final rule allow an exemption for the subject uses until such time as the Commission promulgates a rule pursuant to section 206(b)(2) of the NGPA, determining that an alternative fuel is economically practicable and reasonably available for such agricultural uses or users. All of the exemptions encompassed by § 282.202(a) will become subject to the provisions of such a rule upon its effective date. (*See* 18 CFR 282.203(b).)

IV. Effective Date

This rule grants exemptions from incremental pricing surcharges for certain products and processes described above. Because an exemption is granted by this rule, the 30-day publication prescribed by section 553(d)(1) of the Administrative Procedures Act, 5 U.S.C. 553, is not required before the rule becomes effective. Accordingly, this rule is effective November 16, 1981. However, no user can obtain an exemption provided by this rule until the user files an affidavit in accordance with the Commission's regulations in § 282.204. The effective date of such exemption affidavit is set forth in § 282.204(d)(7).

(Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432; Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.*; E.O. 12009, 42 FR 46267)

In consideration of the foregoing, the Commission revises § 282.202(a)(1)(ii) and (iii) of Part 282, Subchapter I,

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[16] Exemption from Incremental Pricing for Distillers Who Produce Fuel-Grade Alcohol Blended to Form Gasohol, Notice of Proposed Rulemaking, issued June 9, 1980 (45 *Fed. Reg.* 40617, June 18, 1980).

Chapter I, Title 18, Code of Federal Regulations, as set forth below effective November 16, 1981.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,314]

46 F. R. 58292 (December 1, 1981)

18 CFR Part 154

[Docket Nos. RM78-23 and RM81-37; Order No. 194]

Regulations Implementing Procedures for Refund of Louisiana First Use Tax

Issued November 20, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Commission amends and issues as final regulations the interim regulations contained in paragraph (h) of 18 CFR 154.38 relating to recovery and pass-through of Louisiana First Use Tax by interstate pipelines. The regulations are amended in paragraphs (h)(3), which applies to any interstate pipeline which paid the First Use Tax directly to Louisiana ("primary pipelines"), and (h)(9), which applies to any pipeline which receives First Use Tax refunds from other pipelines ("secondary pipelines"), to clarify the refund allocation methodology. Otherwise, the interim rules are being issued as final rules as originally promulgated.

The rules for primary and secondary pipelines were issued in separate dockets. Since the changes effected in the final rules are relatively minor, the Commission combines the two dockets in issuing the final rules.

EFFECTIVE DATES: The final rules are effective upon issuance as of the effective dates of the interim rules: July 17, 1981 for primary pipelines, 18 CFR 154.38(h)(3); July 22, 1981 for secondary pipelines, 18 CFR 154.38(h)(9).

FOR FURTHER INFORMATION CONTACT:

Fredrick L. Jaffe, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-9221.

Sherri L. Booye, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-5378.

SUPPLEMENTARY INFORMATION:

In the matter of Final Rule: Clarification of Regulations Implementing Procedures for Refund of Louisiana First Use Tax by Primary and Secondary Pipelines.

By this rule, the Federal Energy Regulatory Commission (Commission) is amending and issuing as final regulations the interim regulations contained in paragraph (h) of 18 CFR 154.38 relating to recovery and pass-through of Louisiana First Use Tax by interstate pipelines. The regulations are amended in paragraphs (h)(3), which applies to any interstate pipeline which paid the First Use Tax directly to Louisiana ("primary pipelines"), and (h)(9), which applies to any pipeline which receives First Use Tax refunds from other pipelines ("secondary pipelines"), to clarify the refund allocation methodology. Otherwise the interim rules are being issued as final rules as originally promulgated.

The rules for primary and secondary pipelines were issued in separate dockets. Since the changes effected in the final rule are relatively minor, we are combining the two dockets for the final rule.

I. Background

On July 17, 1981 and July 22, 1981, the Commission issued interim regulations[1] which established procedures for refund by the primary and secondary pipelines of Louisiana First Use Tax revenues collected by Louisiana and the interest accrued thereon. The Commission asked interested persons to submit comments to those regulations by August 12, 1981. In response to those requests, the Commission received three comments that raised issues affecting primary and secondary pipelines.

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[1] "Regulations Implementing Procedures for Refund of Louisiana First Use Tax by Primary Pipelines," Interim Rule, 46 FR 38883 (July 29, 1981) and "Regulations Implementing Procedures for Refund of Louisiana First Use Tax by Secondary Pipelines," 46 FR 38906 (July 30, 1981).

II. Discussion of Comments

One party requested waiver of a portion of the refund methodology prescribed for primary pipelines in § 154.38(h)(3)(vi) for determining the jurisdictional portion of all refunds. However, because our response to the request for waiver will apply to all pipelines, we are treating the request as a comment. The commenter points out an inconsistency in the allocation methodology for primary pipelines. While § 154.38(h)(3)(iv)(*a*) of the interim regulations requires allocation of the jurisdictional portion of the refund received on the basis of the amounts paid by each jurisdictional customer as recorded in the pipeline books and records, subparagraph (vi)(*c*) determines the *jurisdictional portion* on the basis of volumes of gas sold with LFUT charges attached. The commenter states that the Commission should allow both the determination of the jurisdictional portion and the allocation of this jurisdictional portion to be based upon the amounts paid as reflected in the pipelines books and records.

Another commenter raised an issue regarding the allocation of refunds between jurisdictional and non-jurisdictional customers applicable to primary and secondary pipelines. The commenter is concerned that the Commission has required that refunds be based upon only those customers who paid the tax rather than based upon the volumes on which the tax was charged. In effect, the commenter believes that under the regulation, if a non-jurisdictional customer did not pay the tax and, under the terms of a fixed rate contract, the pipeline paid the tax, the pipeline would be denied its share of the refund and the pipeline would be required to prorate its share of the refund among its jurisdictional customers. Specifically, the commenter cites the following language of § 154.30(h)(9)(vi)(*c*) as causing the ambiguity:

> The denominator of which is the total volume sold by such pipeline to all customers during such period which were subject to First Use Tax charges.

Another commenter objected to the cash flow-through procedures required in the interim rules when, as in its case, the refunds are extremely small and requested waiver of the provisions. The Commission has treated this objection as a petition for waiver rather than as a comment to the interim rules. Accordingly, the Commission has separately considered the request and has issued an order granting the petitioner's waiver request.[1]

III. Correction and Clarification

In its interim regulations, the Commission inadvertently failed to permit primary pipelines both to determine the jurisdictional portion and to allocate the jurisdictional portion so determined on the basis of the amounts paid as reflected in the books and records of the pipeline. Accordingly, we amend the language in paragraphs (h)(3)(iv) (*a*)(*b*) and (*c*) to make this intention clear.

The Commission intended § 154.38(h)(3)(vi)(*c*) affecting primary pipelines, and § 154.33(h)(9)(vi)(*b*), affecting secondary pipelines, to require that pipelines apportion refunds among jurisdictional customers on the same basis as was used to allocate LFUT costs when incurred. In light of this affirmation of our original intent, we clarify the interim language in paragraph (h)(3)(vi)(*c*) and paragraph (h)(9)(vi)(*b*) to eliminate any possible ambiguity that the refunds must be apportioned on any other basis than what was originally intended.

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[1] "Order Granting Waiver of Interim Rules Subject to Conditions", (Issued September 30, 1981).

The Commission also corrects a typographical error in paragraph (h)(3)(vi).

IV. Effective Date

Because the amendments effect no substantive change in the interim rules, but are necessary only for correction and clarification, the amendments are being made effective as of the date the interim regulations became effective.

(Natural Gas Act, 15 U.S.C. 717–717(n); Department of Energy Organization Act, 42 U.S.C. 7101–7352; Administrative Procedure Act, 5 U.S.C. 553)

In consideration of the foregoing, the interim rules amending § 154.38(h) Part 154 of Title 18 Code of Federal Regulations published in 46 FR 38681 (July 29, 1981), 18 CFR 154.38(h)(3), and 46 FR 38906 (July 30, 1981), 18 CFR 154.38(h)(9), are deemed to be final. In addition, § 154.38(h), Part 154 of Title 18 Code of Federal Regulations, is amended as set forth below. Because this amendment effects no substantive changes, it is effective upon issuance as of the effective dates of the interim rules—July 17, 1981 for primary pipelines and July 22, 1981 for secondary pipelines.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,315]

46 F. R. 58293 (December 1, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Texas-12)]

High-Cost Gas Produced from Tight Formations; Final Rule

Issued: November 20, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recomendation of the Railroad Commission of Texas that the Frio Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective November 20, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8307, or Walter Lawson, (202) 357–8556.

SUPPLEMENTARY INFORMATION:

The Commission hereby amends § 271.703(d) of its regulations to include the Frio Formation in Texas as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by the Director, OPPR, issued July 30, 1981 (46 FR 40044, August 6, 1981)[1] based on a recommendation by the Railroad Commission of Texas (Texas) in accordance with § 271.703(c) that the Frio Formation be designated as a tight formation.

Evidence submitted by Texas supports the assertion that the Frio Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Texas recommendation.

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[1] Comments were invited and one favorable comment was received. No party requested a public hearing and no hearing was held.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and, therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.;* Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3342; Administrative Procedure Act, 5 U.S.C. 553)

In consideration of the foregoing, Part 271 of Subchapter H, Chapter I, Title 18, *Code of Federal Regulations,* is amended as set forth below, effective November 20, 1981.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,316]

46 F. R. 58294 (December 1, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Oklahoma-1)]

High-Cost Gas Produced From Tight Formations; Final Rule

Issued: November 20, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Oklahoma Corporation Commission that the Atoka Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective November 20, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or John Roy Johnson, (202) 357-8731.

SUPPLEMENTARY INFORMATION: The Commission hereby amends § 271.703(d) of its regulations to include the Atoka Formation in Oklahoma as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by the Director, OPPR, issued August 25, 1981 (46 FR 43845, September 1, 1981)[1] based on a recommendation by the Oklahoma Corporation Commission (Oklahoma) in accordance with § 271.703(c) that the Atoka Formation be designated as a tight formation.

Evidence submitted by Oklahoma supports the assertion that the Atoka Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Oklahoma recommendation as amended.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and, therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

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[1] Comments were invited on the proposed rule and none were received. No party requested a hearing and no hearing was held.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3342; Administrative Procedure Act, 5 U.S.C. 553)

In consideration of the foregoing, Part 271 of Subchapter H, Chapter I, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective November 20, 1981.

By the Commission.
Kenneth F. Plumb,
Secretary.

[¶ 30,317]

46 F. R. 58294 (December 1, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Colorado-14)]

High-Cost Gas Produced From Tight Formations; Final Rule

Issued November 20, 1981

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Colorado Oil and Gas Conservation Commission that the Dakota Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective November 20, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8616.

SUPPLEMENTARY INFORMATION: The Commission hereby amends § 271.703(d) of its regulations to include the Dakota Formation in Colorado as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was first proposed in a Notice of Proposed Rulemaking by the Director, OPPR, issued May 4, 1981 (46 FR 25643, May 8, 1981)[1] based on a recommendation by the Colorado Oil and Gas Conservation Commission (Colorado) in accordance with § 271.703(c) that the Dakota Formation be designated as a tight formation. On August 11, 1981, Colorado filed an amendment to its recommendation containing additional data is support of the recommendation. The amendment also deleted some acreage from the recommendation, as Colorado had found that expected production from wells in this area would be in excess of the production guideline found in § 271.703(c)(2)(i)(B). Notice of the deletion of acreage was given by the Commission in a Notice of Proposed Rulemaking issued on August 25, 1981 (46 FR 43843, September 1, 1981.)

Evidence submitted by Colorado supports the assertion that the Dakota Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Colorado recommendation as amended.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and, therefore, incentive prices should be made available as soon as possible.

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[1] Comments were invited and one comment supporting the recommendation was received. No party requested a public hearing and no hearing was held.

The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3342; Administrative Procedure Act, 5 U.S.C. 553)

In consideration of the foregoing, Part 271 of Subchapter H, Chapter I, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective November 20, 1981.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,318]

46 F. R. 58295 (December 1, 1981)

18 CFR Part 271

[Docket No. RM 79-76 (Virginia-1); Order No. 191]

High-Cost Gas Produced From Tight Formations; Adoption of Designation Recommendation

Issued: November 20, 1981.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Virginia Department of Labor and Industry, Division of Mines and Quarries that the Berea Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective November 20, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Walter Lawson (202) 357-8556.

SUPPLEMENTARY INFORMATION: The Commission hereby amends § 271.703(d) of its regulations to include the Berea Formation in Virginia as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by the Director, OPPR, issued July 30, 1981 (46 FR 40044, August 6, 1981)[1] based on a recommendation by the Virginia Department of Labor and Industry, Division of Mines and Quarries (Virginia) in accordance with § 271.703(c) that the Berea Formation be designated as a tight formation.

Evidence submitted by Virginia supports the assertion that the Berea Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Virginia recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and, therefore, incentive prices should be made available as soon as possible. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

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[1] Comments were invited and none were received. No party requested a public hearing and no hearing was held.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*, Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3342; Administrative Procedure Act, 5 U.S.C. 553)

In consideration of the foregoing, Part 271 of Subchapter H, Chapter I, Title 18, Code of Federal Regulations, is amended as set forth below, effective November 20, 1981.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,319]

46 F. R. 60193 (December 9, 1981).

18 CFR Part 271

[Docket No. RM79-76 (New Mexico—6); Order No. 195]

High-Cost Gas Produced From Tight Formations; New Mexico

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

Issued: December 3, 1981.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the State of New Mexico Oil Conservation Commission that the Dakota Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective December 3, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307, or Victor Zabel, (202) 357-8616.

SUPPLEMENTARY INFORMATION:

The Commission hereby amends § 271.703(d) of its regulations to include the Dakota Formation in New Mexico as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by the Director, OPPR, issued September 22, 1981 (46 FR 49466, September 28, 1981)[1] based on a recommendation by the New Mexico Oil Conservation Commission (New Mexico) in accordance with § 271.703(c) that the Dakota Formation be designated as a tight formation.

Evidence submitted by New Mexico supports the assertion that the Dakota Formation meets the guidelines contained in § 271.703(c)(2). One comment was received in response to the Notice of Proposed Rulemaking from Southern California Company (SoCal). SoCal noted that by Order No. R-1670-V, New Mexico authorized infill drilling in the Basin Dakota Gas Pool. Order No. R-1670-C, issued November 4, 1960, consolidated all Dakota gas production in San Juan and Rio Arriba Counties, created the Basin Dakota Gas Pool, and established 320-acres gas proration units. Order No. R-1670-V, issued May 22, 1979, retained the original 320-acre unit spacing, but allowed the drilling of an additional well on each unit. Citing to Commission Order No. 137-A, in Docket No. RM79-76,[2] wherein the Commission excluded from a tight formation designation certain fields in a formation which had been subject to an infill drilling order and had been substantially developed at the time the infill drilling order was issued, SoCal indicated that a similar situtation, requiring exclusion of the infill area, may exist for the recommended Dakota Formation.

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[1] No party requested a hearing in this docket and no hearing was held.

[2] "Order Denying Application for Rehearing of Order No. 137," issued June 17, 1981 (46 FR 32235, June 22, 1981).

The Commission has reviewed SoCal's comments and for the following reasons does not believe that an exclusion of infill areas is required in this case. There are 422 drilling units in the Dakota formation recommended by New Mexico for tight formation designation. Wells have been drilled in 35 of these units, representing 8.3 percent of the available drilling sites. Of the 35 wells drilled, 22 have been abandoned, leaving 13 wells currently producing. All of these Dakota wells are the only wells in their drilling units. There has been been no infill drilling in the area proposed for tight formation designation, and the Commission finds that the area has not been substantially developed, as was the area excluded in Order No. 137. For the reasons stated above, the Commission adopts the New Mexico recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and, therefore, incentive prices should be made available a soon as possible. The need to make incentive prices immediately available establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.;* Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3342; Administrative Procedure Act, 5 U.S.C. 553)

In consideration of the foregoing, Part 271 of Subchapter H, Chapter I, Title 18, *Code of Federal Regulations,* is amended as set forth below, effective December 3, 1981.

By the Commission. Commissioner Sheldon voted present.

Kenneth F. Plumb,
Secretary.

[¶ 30,320]

46 F. R. 60429 (December 10, 1981).

18 CFR Parts 154, 157, 250, and 260

[Docket No. RM81-16; Order No. 196]

Discontinue Producer Reports and Related Form Nos. 108 and 314-B and To Reinstitute and Revise Producer Filing Instructions

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is discontinuing two reporting requirements and the related regulations: FPC Form No. 108 "Rate Schedule Analysis on a Continuing Basis" (18 CFR 260.6), and FPC Form No. 314–B, "Annual Statement for Independent Producers Holding Small Producer Exemptions" (18 CFR 154.104).

In lieu of Form No. 108, which is composed of five separate schedules, the Commission substitute simplified requirements, Format No. FERC 558, "Contract Summary to be Filed by All Applicants for Certificates of Public Convenience and Necessity, Including Successors in Interest" (18 CFR 250.5); and Format No. FERC 559, "Independent Producer Rate Change or Initial Billing Statement" (18 CFR 250.14).

Form No. 314–B is replaced by a requirement that companies file a simple statement with the Commission stating that they have lost their small producer status by producing more than 10 million Bcf of gas per year.

DATE: The revisions in this rulemaking are effective January 6, 1982.

FOR FURTHER INFORMATION CONTACT: Stephen Badzik, Federal Energy Regulatory Commission, Office of Pipeline and Producer Regulation, 825 North Capitol Street, NE, Room 6006–F, Washington, D.C. 20426, (202) 357–8758.

SUPPLEMENTARY INFORMATION:

Issued: December 7, 1981.

By this rule, the Federal Energy Regulatory Commission (Commission) discontinues two of its reporting requirements: FPC Form No. 108, "Rate Schedule Analysis on a Continuing Current Basis," and FPC Form No. 314–B, "Annual Statement for Independent Producers Holding Small Producer Exemptions." Two of the five schedules in Form No. 108 and the supporting documents in the form are deleted in their entirety. In lieu of the other three schedules in the form, the Commission substitutes the simpler reporting requirements of the new Format Nos. FERC 558 and 559. The Commission also replaces Form No. 314–B with a less burdensome reporting requirement. Certain necessary revisions are made to the Commission's regulations to reflect these form changes.[1]

The changes are made as part of the Commission's ongoing program to review all of its reporting requirements, to eliminate requirements that are not necessary to the performance of its regulatory responsibilities and to reduce the burden of filing required data with the Commission. The changes resulting from this rulemaking should reduce respondent reporting burden significantly.[2]

I. Background and Summary of Proposed Changes

A. *Form No. 108.* The filing of the Form No. 108 had been required since 1976 under § 260.6 of the Commission's regulations.[3] The form collected, in a computer format, information from large independent gas producers concerning natural gas flowing in interstate commerce. It was required to be filed each time a rate schedule was submitted to the Commission for the first time or a rate schedule presently on file with the Commission was proposed to be amended. Much of the information in the form had been used for determinations respecting biennial national rate adjustments under section 4 of the Natural Gas Act (15 U.S.C. 717c). With the passage of the Natural Gas Policy Act (NGPA) (15 U.S.C. 3301–3432), however, biennial rate adjustments were discontinued. As a result, most of the data collected in Form No. 108 has become obsolete.

More specifically, two of the schedules in Form No. 108, Schedule No. 501, "Independent Producer Natural Gas Sales Summary," and No. 505, "Independent Producer Annual Rate Schedule Sales Data", collected annual gas sales, volume and revenue reports. These reports became insufficient after passage of the NGPA because they did not collect data required for NGPA compliance purposes. Moreover, the Commission's field audit program has proven to be an effective means of assuring producer and pipeline compliance with the NGPA and with the Commission's regulations. In addition, information about actual gas volumes and revenues can be obtained through specific data requests to the producers and pipeline companies. The Commission, therefore, issued a Notice of Proposed Rulemaking on February 19, 1981 (46 FR 14899, March 3, 1981) proposing, among other things, to discontinue Form No. 108 and the requirements of Schedule Nos. 501 and 505 in that format. The Commission's regulations at § 260.6 that require the filing of Form No. 108 were also proposed to be eliminated.

Schedule No. 502 of Form No. 108 "Independent Producer Rate Schedule Identification and Contract Data" and Schedule No. 503, "Independent Producer Rate Schedule Pricing Provisions and Actual Quality Data" collected summary data about gas contracts. These schedules were filed each time a producer submitted a new contract or contract amendment.

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[1] The Commission's predecessor, the Federal Power Commission, was authorized to collect the information in Form Nos. 108 and 314–B under sections 4, 7, and 10 of the Natural Gas Act (15 U.S.C. 711–717w). Pursuant to section 402(a)(1)(C) and (D) of the Department of Energy Organization Act (42 U.S.C. 7101–7352), the authority under sections 4 and 7 of the Natural Gas Act was transferred to the Commission. The Secretary of Energy delegated the authority of section 10 of the Natural Gas Act to the Commission under Delegation Order 0204–1 (October 1, 1977).

[2] In anticipation of the rulemaking proceeding in this docket, the Commission issued an order on May 5, 1980 to suspend, until further notice, the filing of the two schedules which are deleted from Form No. 108, and the filing of the Form No. 314–B (45 FR 33600, May 20, 1980).

[3] Form No. 108 was promulgated in Order No. 556, Docket No. RM76–10, November 22, 1976 (41 *FR* 52441, November 30, 1976), and was revised in Order No. 556–A, Docket No. RM76–10, August 5, 1977 (42 *FR* 41271, August 16, 1977).

Although the passage of the NGPA makes the filing of much of the data in these schedules unnecessary, sections 4 and 7 of the Natural Gas Act still require that certain information be reported about gas that is "committed or dedicated to interstate commerce" within the meaning of section 2(18) of the NGPA. In the February 19th notice, therefore, the Commission proposed to replace Schedule Nos. 502 and 503 with the new Format No. FERC 558, "Contract Summary to be Filed by all Applicants for Certificates of Public Convenience and Necessity, Including Successors in Interest." This format would be filed with every producer's application for a certificate of public convenience and necessity and would be prescribed under a new § 250.5 of the Commission's regulations. The notice also provided that this requirement would include NGPA pricing data, certain new elements that are required for a certificate application and a few additional clarifying items. The notice further stated that the new Format No. FERC 558 would represent an 82 percent reduction in data elements from Schedule Nos. 502 and 503 and would be designed for human (*i.e.*, noncomputer) responses.

The fifth, and last, of the Form No. 108 schedules is Schedule No. 507, "Independent Producer Rate Change Filing or Initial Billing Statement". Schedule No. 507 reported either the initial rate a producer proposed to charge under its requested certificate for a newly certificated sale of natural gas under section 7 of the NGA, or a change that a producer proposed to make to the rate that it filed under section 4 of the NGA. Many changes in rate filings have been eliminated under the blanket affidavit procedures adopted in Commission Order Nos. 15 and 25.[4] Therefore, in the February 19th notice, the Commission proposed to replace Schedule No. 507 with a new, simpler format to be entitled, "Format No. FERC 559, Independent Producer Rate Change or Initial Billing Statement". The notice proposed that this new format would be required by § 250.14 of the Commission's regulations. It would be required to be filed at the time a certificate to sell gas is submitted, and when a rate change is proposed. Format No. FERC 559 would continue to collect the basic data for new rates or changes in rates and would also require new information for NGPA compliance purposes. Much of the data previously required in Schedule No. 507 would be totally eliminated from the new format, according to the notice. As a result of the proposed deletions in the new, simplified format, there should be a 30 percent reduction in data elements from that previously required.

B. *Form No. 314–B.* Section 154.104 of the Commission's regulations has required the filing of annual reports of interstate sales by small producers in the statement set out in § 250.11. These data were submitted on Form No. 314–B.[5] The report was used to identify small producers and their affiliates whose combined annual jurisdictional sales exceeded 10 million Mcf, so that small producer certificates could be cancelled with respect to future sales. (*See* 18 CFR 157.40(a)(1) and (d).)

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[4] Order No. 15, "Amendments to the Commission's Regulations Relating to Independent Producer Filing Requirements", Docket No. RM79–4 (issued November 17, 1978), 43 FR 55756 (November 29, 1978), amended by Order No. 15–A, "Amendments to the Commission's Regulations Relating to Independent Producer Filing Requirements", Docket No. RM79–4 (issued December 28, 1978), 44 FR 1100 (January 4, 1979); Order No. 25, "Amendments to the Commission's Regulations Relating to Independent Producer Filing Requirements", Docket No. RM79–31 (issued March 27, 1979), 44 FR 19389 (April 3, 1979).

[5] Although Form No. 314–B was not specifically mentioned in either § 154.104 or § 250.11, the data prescribed in § 250.11 were required through Commission practice to be reported by respondent companies on the Form No. 314–B. Section 250.11 was promulgated in Order No. 308, "Rate and Certificate Filings by Small Independent Producers", Docket No. R–279 (issued October 29, 1965), 30 FR 14099 (November 5, 1965), amended by Order No. 428–A, "Exemption of Small Producers From Regulation", Docket No. R–393 (issued April 9, 1971), 36 FR 7233 (April 16, 1971), and also amended by Order 428–D, "Exemption of Small Producers From Regulation", Docket No. R–393 (issued May 4, 1972), 37 FR 9659 (May 12, 1972).

Because the NGPA now prescribes the maximum statutory prices for producer sales in both interstate and intrastate markets, the annual report of interstate small producer sales are of minimal value to the Commission. Therefore, the notice proposed the elimination of the Form No. 314-B and the reporting burden it represented. In lieu of this requirement, the notice proposed that companies file a simple statement with the Commission, described in 18 CFR 157.40(a), that they have lost their small producer status if and when their jurisdictional sales exceeded 10 million Mcf during the previous calendar year.

II. Summary and Analysis of Comments and Changes

The Commission received comments from seven natural gas producers and an interested party in response to the Notice of Proposed Rulemaking.[6] All of the comments, at least generally, supported the eliminations proposed in this rulemaking.[7] One commenter stated that eliminating Schedule Nos. 501 and 505 of Form No. 108 will result in savings of approximately 250-300 man-hours per year. Two other commenters stated that the revised reporting requirements were more practical than the existing forms. Another added that the revised requirements provide all of the information necessary for the analysis of proposed rate schedules under the Natural Gas Act and the NGPA and they alleviate the burdens on producers of providing information that is no longer necessary for the Commission's analysis of gas rate schedules. The Commission has, therefore, adopted the changes to §§ 154.92, 154.94, 154.104, 157.24, 157.40, 250.11 and 260.6, that were proposed in the Notice of Proposed Rulemaking.

Several of the commenters also offered suggestions for changes to Format No. 558 (new § 250.5) and to Format No. 559 (new § 250.14). With respect to the changes for Format No. 558, one company said that Item (8), "Total price in dollars per MMBtu (including all adjustments and tax reimbursement)" should require only a statement of total price in dollars per MMBtu, exclusive of any adjustments for lawful add-ons. With respect to Item (9), which elicits a separate specification of adjustments included in the total price per MMBtu, the company said that the item should prescribe a specification of adjustments in the mode actually billed and received, whether in cents per MMBtu, per Mcf, or otherwise. According to this company, these changes to Items (8) and (9) would simplify the reporting requirement with respect to the burdensome conversion of data from MMBtu to Mcf or some other basis.

The Commission agrees with these suggestions and has amended Item (8) to require the base price in dollars per MMBtu (exclusive of any statutory adjustments and tax reimbursements) and has clarified Item (9) to require a report of the statutory adjustments including tax reimbursements to be added to the base price in Item (8). The footnote to Item (9) has also been clarified to require the amount for each type of statutory adjustment in the manner actually billed and received, either in cents per MMBtu or Mcf.

The company also suggested that Item (10), "Estimated Sales Volumes (Mcf per month)" should be modified to specify which "month" is involved (*i.e.*, month of initial deliveries, or peak production, or average month's production over a long period). This commenter added that Item (10) should provide that the data reported do not constitute a representation or warranty of gas availability by the seller.

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[6] Comments were submitted by: Champlin Petroleum Company; Conoco, Inc. (concurring with Exxon's comments); Exxon Corporation; Henderson Clay Products, Inc.; Santa Fe Energy Company; Shell Oil Company; Sun Gas Company, a Division of Sun Oil Company; and Texas Gas Exploration Corporation, a subsidiary of Texas Gas Transmission Corporation.

[7] One commenter supported the proposed discontinuance of Form No. 314-B and added that it "did not disagree" with the proposed requirement to report the loss of small producer status instead of the requirement to file an annual report.

The Commission has clarified Item (10), as suggested. The estimated sales are "for the first month of deliveries." In addition, the Commission will require that these sales be reported in MMBtu or Mcf, to be consistent with the requirement in Item (9). However, the Commission need not state that the reported data in Item (10) do not constitute a representation or warranty of available gas, because only "estimated" sales volumes are requested in that item. Such information of course, would not be warranted.

The company also suggested that Item (11), "Delivery Pressure" should specify whether a statement of maximum/minimum contract pressures or a statement of anticipated actual working pressure is required. In addition, the commenter stated that this item should also provide that the data reported do not constitute a warranty of delivery pressure by the seller.

In response to this suggestion, the Commission has clarified Item (11). What will be required is the "estimated delivery pressure" of the reported gas. The Commission believes that this terminology is more accurate than the suggested "anticipated actual working pressure". As in Item (10), these estimated data are not supposed to constitute a representation or warranty of delivery pressure.

Finally, this company claimed that clarification was needed in Item (13), "Other special conditions affecting price", as to the type of information required. As a result, the Commission has reexamined Item (13) and has determined that it is not necessary, because sufficient data respecting conditions that affect price are reported elsewhere in the format. Therefore, Item (13) has been entirely deleted from the form.

Three of the commenters offered several suggestions for revisions to Format No. FERC 559 (the proposed § 250.14). First, they criticized the "Note" that follows the format heading that, among other things, provides the requirements for filing tax reimbursement data. Each of these commenters objected to the statement: "Applications filed to collect rates at Natural Gas Act or contract rate levels must include tax items 9(a) through (e)". They argued that, because there are now only NGPA rates and not NGA rates, the work "tax" is misused in the sentence. They also requested clarification of the terms "NGPA rate" and "contract rate" in the Note. One of these commenters noted that all rates are, in fact, NGPA rates, even where the Commission's NGA jurisdictions is retained. Another suggested that tax reimbursement data should be furnished only when the producer collects contract rates that are different from applicable NGPA rates.

These commenters also criticized the requirement in the "Note" for a statement, under oath, that such producer "will be reimbursed only for taxes actually paid, to the extent contractually authorized". One of the commenters said that the Commission does not seek tax reimbursement data for NGPA rates and two commenters stated that the oath requirement simply restates the statutory requirements of sections 110 and 504 of the NGPA and § 271.1102(a) of the Commission's regulations. One company suggested that the oath requirement could be replaced by an estimate of the taxes to be collected.

The Commission has revised Format No. 559 by, among other things, entirely eliminating the "Note" and its oath requirement, and by adding several instructions to clarify the requirements in the format.[8] With respect to the Note, the Commission has transferred the reporting of tax reimbursements to "Other adjustments" (the new Item (11)(c)). The instruction for Item (11)(c) has been clarified to specifically provide that "Other adjustments" includes tax reimbursements (if the change is to the base rate, other than to the maximum lawful price under the NGPA), dehydration, compression, etc. Although the Commission does not agree that the oath provision restates requirements in the NGPA and the regulations, the Commission does agree that the oath is not an essential requirement to the format and can be eliminated.

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[8] The Commission also rearranged the items in the format so that they are presented in a more logical manner and made other minor revisions, such as requiring the Field *or* Plant and the County *or* Parish identification in the new Item (6), and also requiring in Item (15) the name and telephone number of a contact person, as necessary.

One of the commenters requested clarification of Item (8) of Format No. FERC 559, "Regulation Section (type of change)." The commenter also suggested that Items (12) and (13) (data respecting future NGPA escalations under § 154.94(h) affidavits, and reports of rate applications under sections 102(d) or 108 of the NGPA, respectively) should be grouped immediately after Item (8), for ease of reporting.

In response to this comment, the Commission has clarified Item (8) (new Item (6)) by eliminating the requirement to identify the section of the regulations that pertains to the filing, because it creates an added burden that is not essential to the Commission's regulation. Instructions have been added to Item (6), specifying the type of rate change to be reported. The Commission has also moved Items (12) and (13) (new Items (9) and (10), respectively), to follow the three related items, "Type of Change" (new Item (6)), "Contract Basis" (new Item (7)), and "Proposed Effective Date" (new Item (8)).

Two of the commenters stated that Item (9), "Rate Information" should not require that data be reported on both an MMBtu and Mcf basis. According to one of these commenters, the necessary conversion calculations to do this would be difficult. The Commission believes that the reporting of rate information in this format will be acceptable either in MMBtu's or Mcf's. The instructions to Item (9) (new Item 11) have been revised accordingly.

One company stated that Item (9)(b), "Btu adjustment" should be changed to require estimated data, because the Btu content of gas can change over a period of time. This company also recommended that Item (9) be placed immediately before Item (14). "Remarks" because explanations of (9)(d), "Other, explain" would be made in Item (14).

The Commission has determined that information about the sales volumes and the Btu content of gas is not really needed for establishing qualification to collect the maximum lawful price for such gas. When the Commission needs information about volumes and Btu content, it can collect it in specific data requests. As a result, the proposed Items (9)(b), (10) and (11) can be entirely eliminated from the new format. In addition, Item (9) (new Item (11)) has been placed immediately before Item (14) (new Item (12)), as suggested.

A commenter requested clarification of Item, the proposed Item (12), by asking whether future NGPA escalations are to be covered by blanket affidavits filed under § 154.94(h) of the Commission's regulations. The commenter argued that a "yes" response to the inquiry would appear to obviate further filings of Format No. FERC 559.

As suggested, the Commission has included a clarifying instruction for Item (12) (new Item (9)). This item pertains only to the first sales of gas for which qualification to collect the NGPA base rate under § 154.94(h) is being established by Format No. FERC 559. Section 154.94(h) permits producers who are contractually authorized to collect NGPA maximum lawful prices to state that such first sales will be covered by a previously-submitted blanket affidavit.

One commenter recommended a change to the proposed Item (13)(b), which requires the effective date of the final determination of a rate application under section 102(d) or 108 of the NGPA. Since the Commission does not publish the date of a final determination, the commenter suggested that Item 13(b) should require "the date of filing a determination with the Commission, as published in the Federal Register." The

Commission agrees with this suggestion and has accordingly changed Item (13)(b) (new Item (10)(b)) to read, "Date jurisdictional agency's well determination is received by the FERC, as published in the Federal Register."

Finally, one commenter suggested that the address requirement in Item (15)(c) (new item (13)) should provide for the use of Post Office numbers as an alternative to a street address. The Commission agrees with this recommendation and has merely left the address line blank, so that any appropriate address can be inserted.

III. Effective Date

The changes in this final rule will be effective January 6, 1982.

(Natural Gas Act, 15 U.S.C. 717–717w; Department of Energy Organization Act, 42 U.S.C 7101–7352; E.O. 12009, 3 CFR Part 142)

In consideration of the foregoing, the Commission amends Parts 154, 157, 250 and 260 of Chapter I, Title 18, Code of Federal Regulations, as set forth below.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,321]

46 F. R. 60813 (December 14, 1981).

18 CFR Part 300

[Docket No. RM82-6]

Confirmation and Approval of the Rates of the Bonneville Power Administration; Interim Rule

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Interim rule.

SUMMARY: The Federal Energy Regulatory Commission is amending its rules on an interim basis to establish procedures for the interim acceptance of rates submitted by the Bonneville Power Administration under section 7 of the Pacific Northwest Electric Power Planning and Conservation Act.

Specifically, the Commission is adding a new Part 300 to its rules which will provide general procedures, filing requirements and standards for Commission rate review with respect to rate schedules submitted by the Bonneville Power Administration for confirmation and approval. Part 300 is part of a new Subchapter L which is designed to contain all Commission regulations relating to the rates of Federal power marketing agencies.

The rule is being promulgated on an interim basis and is subject to notice and comment procedures before approval on a final basis. Interim approval of the rule is necessary in order to meet the December 5, 1981 statutory deadline. The rule applies only to the Bonneville Power Administration.

DATES: This interim rule is effective December 4, 1981. Comments must be submitted on or before February 5, 1982.

ADDRESSES: All comments must be mailed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

All comments should reference Docket No. RM82-6.

FOR FURTHER INFORMATION CONTACT: James Hoecker or Michael Kessler, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8033.

SUPPLEMENTARY INFORMATION:

Issued: December 4, 1981.

The Federal Energy Regulatory Commission (Commission) is amending its rules, on an interim basis, to establish procedures for the interim acceptance of rates submitted by the Bonneville Power Administration (BPA) under section 7 of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act or Act).[1] Specifically, the Commission is adding a new Part 300 to its rules which will provide, with respect to rate schedules submitted by the BPA for confirmation and approval: (1) General procedures; (2) filing requirements; and (3) standards for Commission rate review. Part 300 is part of a subchapter L which is designed to contain all Commission regulations relating to the rates of Federal Power Marketing agencies.

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[1] 16 U.S.C. 839–839h (1980). This rule applies only to the BPA.

The rule is being promulgated on an interim basis to comply with a statutory deadline established by Congress in subsection 7(i)(6) of the Northwest Power Act. Under that subsection, the Commission must implement procedures by December 5, 1981, if any, for the approval on an interim basis of the final rate established by the Administrator of the BPA. Rates promulgated by the Administrator of the BPA may not become effective on a final basis until they are confirmed and approved by the Commission.

I. Background

Section 7 of the Pacific Northwest Act [2] contains the basic rate directives for the sale and transmission of electric power by the BPA.

Section 7(a)(1) of the Northwest Power Act requires the Administrator of the BPA to establish and periodically review and revise BPA rates to recover, in accordance with sound business principles, the Federal investment in the Federal Columbia River Power System. In establishing rates, the Administrator of the BPA must comply with the substantive requirements of subsection 7(a)(1) and 7(b) of the Northwest Power Act and the procedural requirements of subsection 7(i) of that Act. Subsections 7(i)(1) through (5) of the Northwest Power Act contain extensive notice, hearing, and decisional requirements that the Administrator must follow in establishing rates.

The Commission's role in the BPA ratemaking process is set forth in subsections 7(a)(2), 7(i)(6), 7(k) and 7(l) of the Northwest Power Act which require the final rates established by the Administrator to be submitted to the Commission for confirmation and approval in order to become effective on a final basis. This continues the scheme of previous statutes governing establishment of BPA rates insofar as the Administrator is required to develop rates through separate ratemaking procedures and the Commission is required to confirm and approve on a final basis those rates set by the Administrator.

Under section 7(k) of the Northwest Power Act, rates for the sale of non-firm electric power within the United States but outside the Pacific Northwest region [3] (non-regional rates) may be accorded somewhat different treatment than that specified for rates generally. These non-regional rates are established by the Administrator of the BPA in the same manner as rates for firm and non-firm service within the region. However, rates for services outside the region may be subject to different standards of review by the Commission before they may become effective on a final basis.

Subsections 7(a)(2) and 7(i)(6) of the Northwest Power Act authorize the Commission to approve rates submitted by the Administrator of the BPA on an interim basis. Subsection 7(i)(6) states that the Commission "shall have the authority * * * to approve the final rate submitted by the Administrator on an interim basis, pending the Commission's final decision in accordance with [section 7(a)(2)]." Subsection 7(l) provides that the interim rate approval provisions in subsection 7(i)(6) also apply to rates for BPA electric power sales to entities outside the United States if those rates are established other than by negotiation.

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[2] 16 U.S.C. 839e.

[3] The Pacific Northwest region is defined in Section 3(14) of the Northwest Power Act, 16 U.S.C. 839a(14), to include all of Oregon, Washington and Idaho and parts of Montana, Nevada, Utah, and Wyoming.

II. Issues Relating to Interim Approval of BPA Rates

The Commission has authority to approve BPA rates on an interim basis before it confirms and approves them on a final basis. The Commission is exercising its interim rate approval authority in this docket by means of an interim rule. However, the interim procedures established will be subject to further refinement based on public comment and further consideration by the Commission. In addition to comment on other features of the rule, the Commission specifically invites comment on the following issues.

A. Establishment of Procedures for Interim Rate Approval

Subsection 7(i)(6) of the Northwest Power Act states that: "[P]ending the establishment of * * * procedures [for the filing of interim rates] by the Commission, if such procedures are required, the Secretary [of Energy] is authorized to approve such interim rates during such one-year period in accordance with the applicable procedures followed by the Secretary prior to the effective date of this Act."[6]

The Commission believes that subsection 7(i)(6) of the Northwest Power Act is most reasonably interpreted to mean that any Commission procedures for interim rate approval must be developed within one year of enactment. Without such procedures, the Commission would still be required to review any BPA rate prior to any interim approval using only procedures and standards provided in the Act, or developed in such case. In other words, the Commission finds nothing in the Act which makes the authority to approve rates on an interim basis contingent on the establishment of such procedures. Rather, the Commission believes that this interim rate approval authority is transferred to the Commission on December 5, 1981 and that no corresponding authority will thereafter remain with the Secretary.

The Commission is establishing appropriate procedures under which it will consider BPA rates for which interim rate approval is requested by the Administrator, primarily to standardize the rate filing and approval procedures and to provide sufficient notice of Commission requirements.

The Commission has determined that establishing procedures for rate approval on an interim basis, prior to December 5, 1981, will obviate most questions relating to the effective transfer to the Commission of the Secretary's authority to approve a BPA on an interim basis. In addition, there are important benefits to be obtained from such procedures. Although the Commission is not required to permit BPA to collect rates and charges on an interim basis, the promulgation of uniform filing requirements, and publication of the appropriate standards of review of such rates will benefit BPA, the purchasers of BPA power, and the Commission.

The Commission anticipates that approval of an interim rate, subject to refund with interest, will protect BPA customers while permitting BPA to meet reasonable revenue requirements without undue regulatory delay or repeated rate proceedings and filings with the Commission. The filing requirements which apply to the Administrator, including the general data and supporting rate schedule and technical analysis, and the procedures for addressing deficient applications, will be necessary for the Commission's final determinations, whether or not the Commission chooses to exercise its discretion to confirm and approve any rate on an interim basis.

B. Rates for Service Outside the Region Versus All Other Rates

The Commission may approve all BPA rates on a final basis under section 7 of the Act. However, the statute makes a distinction between rates for non-firm service to customers outside the Pacific

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[6] The Secretary delegated interim rate approval and authority for all Federal Power marketing agencies to the Assistant Secretary for Resource Applications, under Delegation Order No. 0204-33, 43 FR 60636 (Dec. 28, 1978).

Northwest and all other rates. The implication of this distinction for interim rate approval is not entirely clear. The Commission must first ascertain whether it may approve rates for non-regional service on an interim basis and then determine the appropriate standard of review it must apply when considering interim approval.

Although the Commission may approve on an interim basis all rates governed by subsection 7(a)(2), subsection 7(k) addresses only indirectly the Commission's authority to approve rates for non-regional service on an interim basis. Both the legislative history and public policy argue for the Commission's authority to grant interim rate approval for non-regional service established under subsection 7(k) in the same manner as all other BPA rates.

The legislative history of the Act states that:

> the new rate provisions of the Act are different from past rates of BPA and must be implemented very rapidly on a timetable that the Act will set forth. The bill now provided FERC reasonable options to assure that BPA rates can become effective on a timely basis * * *. What matters, given the need for new rates and for BPA to meet its repayment obligations, is that interim approval be granted quickly.[5]

Congress made no differentiation among rates for various services when it stated this desire for the Commission to act expeditiously in granting interim rate approval. Historically, BPA has relied on rates for non-regional as well as regional service to generate sufficient revenues to meet its repayment obligations.

As a practical matter, approval of any rate on an interim basis will benefit the BPA without imposing an undue corresponding burden on customers outside the Pacific Northwest region. Adverse effects may, in fact, result from precluding interim approval for rates for non-regional service. First, the BPA may request interim approval to bridge immediate revenue deficiencies. Denial of such approval might create serious cash flow problems.

Second, the absence of interim rate approval authority for rates for non-regional service could result in two kinds of disassociated BPA rates that are not "synchronized" with respect to the period during which such rates would be effective. This lack of synchronization of rates may produce difficulties for both the Administrator's calculation of revenues and the Commission's review of the cost evaluation period.

The interim rule is predicated on the belief that approval of rate schedules for non-regional service on an interim basis can be accomplished so as to minimize an undue financial burden on all BPA customers prior to final confirmation and approval. All customers will be protected by the express condition that interim rates will only be approved subject to refund with interest. Any revenues collected in the interim in excess of the rate level finally confirmed and approved would be required by the rule to be returned to BPA customers.

2. *Standards of Review.* BPA rates established under procedures applicable to the Administrator are reviewable by the Commission. With respect to rates other than those addressed in subsection 7(k) of the Act, the statute does not identify a specific level or standard of review to be applied at the interim approval stage other than to state that the Commission's confirmation and approval authority is exercised "pursuant to subsection (a)(2) * * *." Subsection 7(k) states that non-regional rates "shall become effective after review by the Federal Energy Regulatory Commission for conformance with [the Bonneville Project Act,[6] the Flood Control Act of 1944,[7] and the Federal Columbia River Transmission System Act [8]]."

Subsection 7(k) of the Northwest Power Act also requires the Commission to afford the parties to the proceedings under subsection 7(i) an opportunity for a hearing in accordance with the procedures established for ratemaking pursuant to the Federal Power Act. Such hearing would be in addition to any hearings afforded by the Administrator. No requirement of this type is contained in subsection 7(i)(6) regarding rates generally.

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[5] Congressional Record, September 29, 1980 at H9854. —— Cong. Rec. H9854 (daily ed. Sept. 29, 1980) (remarks of Mr. Swift).

[6] 16 U.S.C. 832.

[7] 33 U.S.C. 701.

[8] 16 U.S.C. 838.

The Commission will provide uniform treatment of all BPA rate filings for acceptance and approval on an interim basis and will carry out the statutory objective of placing BPA rates into effect promptly under both subsections 7(i) and (k). The participation of interested persons in the Commission's confirmation and approval process, including any hearings, protests, and interventions, will occur during the period in which a rate is effective on an interim basis, subject to the protection afforded by refunds, but before the rate is approved on a final basis. Notice of rate schedule filings and any action on interim rate requests will be published in the Federal Register, at which time interested persons may request to participate in the final rate approval process.

The Commission is providing procedures for action on requests by the BPA for interim rate acceptance. Upon receipt of a complete application of the Administrator, the Commission may either: (1) order the rate schedule into effect on an interim basis; (2) deny the Administrator's interim rate request and reject the application; or (3) deny the Administrator's interim rate request and review the application for final confirmation and approval. The Administrator's interim rate request will be rejected if the Commission determines that the application is either patently deficient with respect to the filing requirements described below, or, if it fails to comply with the applicable provisions of the Northwest Power Act.

C. Condition of Acceptance of Interim Rates

As an express condition to the acceptance of any rate on an interim basis, § 300.20(c) of the interim rule requires that the rate approved be subject to refund with interest, if the final rate is lower than the rate approved by the Commission to be collected on an interim basis. The amount refundable is further limited to the amount of the rate increase. This refund provision serves the purpose of allowing the BPA's rates to become effective as quickly as possible while providing the customers protection against excessive rates and charges.

1. *Authority To Order Rates Subject To Refund.* Subsections 7(a)(2), 7(i)(6) and 7(k) of the Northwest Power Act do not expressly grant the Commission refund authority. The House Commerce Committee report, however, clearly indicates that the Commission may establish a provision for refunds, if the final rate approved by the Commission is less than the interim rate.[9] Congress thereby recognized the need to afford this protection to the BPA customers who would be charged under a rate schedule not finally approved by the Commission.

In recognition of the legitimate interests of both the BPA and its customers, the Commission will exercise its discretionary authority not to grant interim rate approval, unless BPA agrees to refund with interest any portion of a rate increase under a rate schedule approved on an interim basis which is demonstrated to be excessive when the rate schedule is finally confirmed and approved. A request by the Administrator for interim rate approval shall constitute a tacit agreement to refund with interest under the rule.

Refunds may be accomplished by means of net energy billing.

2. *Interest.* The second issue regarding the refund requirement is the appropriate interest rate to be paid by the BPA if its interim rate proves excessive. Various computational

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[9] *See* H. Rep. 96-976 Pt. 1 (Commerce), 96th Congress, 2nd Sess. at 70.

approaches are available. Section 35.19a(a)(2) of the Commission's rules contains the interest provisions applicable to refunds under rate schedules filed by public utilities under the Federal Power Act (FPA).[10] The position of the BPA in the Nation's financial markets is dissimilar to that of public utilities regulated under the FPA. The FPA interest on refund provision would therefore appear inappropriate for refunds by a power marketing agency.

The Commission proposes that the interest be computed on the periodic outstanding balance of any overcharge at the rate or rates of interest charged to the BPA by the U.S. Treasury during the period. Under certain circumstances, other rates may better reflect BPA's cost of money and therefore the interim rule also allows the Commission or a reviewing court to prescribe another form of interest. This interest methodology is derived from the method established by the BPA and utilized in § 35.13a(d)(4)(v) of the Commission's rules, relating to the BPA Average System Cost Methodology.[11]

III. Summary of the Interim Rule Governing Interim Rate Review

A. Subpart A—General Provisions

1. *Section 300.1—Applicability and Definitions.* Subpart A contains the General Provisions of the interim rule. Section 300.1(a) establishes the applicability of the new Part 300.

Section 300.1(b) contains definitions of "cost evaluation period," "electric service," "historic period," "initial capital investment", "interest group", "power repayment study", "proposed rate approval period", "rate schedule", and "replacement."

2. *Section 300.2—Staff Guidance.* Section 300.2 allows the Administrator to seek guidance from Commission staff prior to submitting an application for confirmation and approval of a rate schedule.

B. Subpart B—Filing Requirements

Subpart B of the interim rule lists the documents required to be filed by the Administrator in any application for confirmation and approval of rates. These filing requirements apply to both interim and final rate approval.

There are three categories of documents required to be filed where the Administrator seeks confirmation and approval of rates: a description of general rate schedule information, supporting cost and revenue data, and a description of analytical approaches to the data.

1. *Section 300.10—Application for Confirmation and Approval.* Section 300.10 contains the general filing requirements, including a letter of request for rate approval, a notice of filing suitable for publication in the Federal Register, the rate schedules, and the Administrator's Record of Decision.

The Administrator's letter requesting rate approval should specify the period for which approval is requested. Because of rapidly changing conditions and escalating costs, recent filings have been on an annual basis. Past practice of this Commission and its predecessor has been to approve requested rate approval periods which do not exceed five years. Although the Commission would expect to continue this practice, the Administrator has the responsibility to review costs and revenues annually and to develop and file new rates if existing rates are found to be deficient in providing adequate revenues for repaying the Federal investment.

Section 7(i)(5) of the Northwest Power Act requires the Administrator to make a final decision establishing rates based "on the record" and to provide a full and complete justification of that decision. This statutory requirement has become embodied in a document called the Administrator's Record of Decision. Section 300.10(e) of the interm rule requires the Administrator to file this document which, at a minimum, shall discuss: a calendar history of the ratemaking process, a discussion of issues raised, a discussion of all applicable statutory and regulatory requirements, a description of the methodology used for determining revenue requirements, and any cost-of-service studies used by the Administrator in developing the rates.

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[10] See 16 U.S.C. 824(e).

[11] Interim Rule, "Sales of Electric Power to the Bonneville Power Administration—Methodology and Filing Requirements," (Docket No. RM81-41), issued October 1, 1981, 46 FR 50517, October 14, 1981.

Section 300.10(a)(2) of the interim rule allows for the incorporation by reference of information that has previously been submitted to the Commission in substantially the same form.

Section 300.10(a)(3) allows the Director of the Office of Electric Power Regulation to notify the Administrator of any deficiencies in the filing. A filing that is patently deficient will not be considered for interim rate approval until such deficiencies are cured.

Section 300.10(a)(4) requires the Commission to publish in the Federal Register, with the Notice of Filing, an opportunity to protest or intervene in the final confirmation and approval proceeding for the filed rate schedule.

Section 300.10(f) of the interim rule requires the Administrator to file with the Commission any other materials not specified in Subpart B which are otherwise required to be developed by the Administrator, specifically under Subsection 7(i)(5) of the Act.

2. *Section 300.11—Technical Support for the Rate Schedule.* Section 300.11 establishes the technical supporting data required to be filed by the Administrator in support of a request for confirmation and approval. The supporting data is divided into two related categories: data statements and analysis of that data. For purposes of consistency and ease of reference, § 300.11(a) of the interim rule specifies the content of six basic statements which are considered to provide the basic underlying data that is required to develop a study to demonstrate that the proposed rates are sufficient to assure repayment of the Federal investment and other costs over a reasonable period of years.

The date statements are identified as: Statement A—Sales and Revenues; Statement B—Power Resources; Statement C—Capitalized Investments or Costs; Statement D—Interest Expenses; Repayment of Investments and Debt Capital; Statement E—Operation, Maintenance and Other Annual Expenses; and Statement F—Cost Allocations.

Section 300.11(b) requires the Administrator to provide an analysis of the information submitted in Statements A through F. The Administrator is authorized to use any appropriate analytical methodology, including a Power Repayment Study.

Traditionally, the various Federal power marketing agencies (PMAs), have used the so-called Power Repayment Study (PRS) method to demonstrate that forecasted annual project or system revenues will be adequate to recover forecasted annual costs and to recover the Federal investment within a reasonable period of years. A PRS is prepared to determine whether the revenues that can be obtained from existing wholesale rates will be sufficient to repay all obligations assigned to the power system within the established repayment periods. Repayment studies are based upon year-by-year forecasts of system revenues and costs over the repayment period. There is no annual schedule of capital repayment. The test of sufficiency of revenues is whether the capital investment can be repaid within the overall repayment period established for each power project, each increment of investment in the transmission system, and each block of irrigation assistance. This approach to repayment scheduling has the effect of averaging the year-to-year variation in costs and revenues over the repayment period.[12]

The normal payout period for a Federal reservoir project has been administratively and statutorily established at 50 years. An analyst preparing a PRS in the early phase of a project's life may, therefore, be required to forecast conditions 50 years in the future.

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[12] H. Rep. 7400, Committee on Interior and Insular Affairs, Hearing before the Subcommittee on Irrigation and Reclamation, 89th Congress, 1st Sess. (September 9 and 10, 1965) at 72.

In a recent report, the General Accounting Office recommended that the BPA revise its methodology for use in the 1983 BPA rate proposal. On January 16, 1981, the Assistant Secretary of Energy for Resource Applications (the predecessor to the Assistant Secretary for Conservation and Renewable Resources) approved a staff recommendation to encourage BPA to explore other methodologies that may be more appropriate for use under the Northwest Power Act. It is the responsibility of the Administrator to develop whatever analytical techniques may be required to demonstrate that revenues will be adequate to meet statutory requirements.

Changes in the methodological approach may require consultation with Congress and other Federal agencies.

If the Administrator develops a new method of analysis, the Commission encourages the Administrator to seek staff guidance, pursuant to § 300.2 of this rule, before filing a new method of analysis.

C. Subpart C—Commission Rate Review and Approval

Subpart C of the interim rule establishes procedures that relate specifically to interim approval of rates.

1. *Section 300.20—Interim Confirmation and Approval.* Under § 300.20(a), the Administrator is required to tender a complete request for approval of a rate on an interim basis under Part 300 not later than 90 days prior to the requested effective date.

Section 300.20(c) sets forth those actions the Commission may take on a request for interim rate acceptance. The fundamental prerequisite is that the Administrator file an application that complies with the requirements of Part 300. Upon receipt of a complete application, the Commission may take any of three possible courses of action. First, it may order the rate schedule into effect on an interim basis, effective on the date requested by the Administrator or such other time as the Commission may otherwise order. Second, if the Administrator's application is either patently deficient with respect to the filing requirements of Part 300 or fails to comply with the applicable provisions of the Northwest Power Act, the Commission may reject the application. Finally, the Commission may deny the Administrator's interim rate request and review the application for final confirmation and approval.

Section 300.20(c) states that the Commission will approve rates on an interim basis only if such rates are subject to refund with interest. The interest rate methodology adopted conforms with the rate or rates of interest charged to the BPA by the U.S. Treasury during the period unless another form of refund is ordered by the Commission.

Section 300.20(d) provides for publication of notice of acceptance of rates, or any other Commission action specified in § 300.20(b), both in the Federal Register and by mail.

IV. Certification of No Significant Economic Impact

The Regulatory Flexibility Act (RFA) requires certain analyses of proposed agency rules that will have a "significant economic impact on a substantial number of small entities."

Pursuant to section 605(a) of the RFA, the Commission hereby finds that the analysis requirements set forth in the rulemaking do not apply to this rulemaking, for the following reasons.

This rule imposes requirements only on the BPA. The BPA is not a "small entity" under the RFA.

The primary purpose of this proposal is to establish procedures for the confirmation and approval of BPA rates for compliance with statutory standards. Under the Pacific Northwest Act, the Commission does not itself set rate levels as it may under the Federal Power Act. The procedures are designed to avoid delays which in the past have accompanied the filing of BPA rates and to implement the Congressional directive to process rate schedules expeditiously. The rules will enable the Commission to place a rate into effect and to reach a decision quickly about its compliance with the statute.

Because this rule applies only to BPA and is procedural in nature, it will not create any impact upon small entities. Hence, the Commission believes a certification of no significant economic impact is entirely proper.

V. Comment Procedures

The Commission invites public comment on the interim rule. The Commission seeks comment particularly on the issues raised relating to confirmation and approval of BPA rates on an interim basis. All comments and views will be considered before the Commission takes final action in this docket.

Written comments on the interim rule must be received by the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, no later than February 5, 1982. Comments should refer to Docket No. RM82-6. Fourteen copies of each comment should be submitted with the original.

Written comments will be placed in the Commission's public files and will be available for inspection during regular business hours in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426.

VI. Effective Date

In accordance with the provisions of 5 U.S.C. 553 (b) and (d), the Commission finds good cause to make Part 300 effective on an interim basis at the time of its issuance and to conduct public procedures during the interim effective period. The Northwest Power Act requires implementation of interim rate approval procedures, if any, by December 5, 1981, and this requirement makes advance notice and comment impracticable at this time. Since any rate which could be placed into effect under this interim rule would be subject to the refund, with interest, of any charges determined upon further analysis to be excessive in light of statutory standards, the Commission believes that an immediate effective date is consistent with the public interest. If the Commission were unable to establish generic procedures for approving rates on an interim basis, there could be undue delays in placing BPA rates into effect which would be contrary to both the legislative intent to expedite treatment of BPA rates and the public interest. The Commission will receive and consider comments on the interim rule.

(Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. 839–839h (1980); Federal Power Act, as amended, 16 U.S.C. 792–828c; Bonneville Project Act, 16 U.S.C. 832–832l; Flood Control Act of 1944, 16 U.S.C. 825s; Federal Columbia River Transmission System Act, 16 U.S.C. 838–838k; Department of Energy Organization Act, 42 U.S.C. 7101–7352 (1978); E.O. 12009, 3 CFR 142 (1978))

In consideration of the foregoing, the Commission amends Chapter I, Title 18 of the Code of Federal Regulations, as set forth below, effective on an interim basis on the date of issuance.

By the Commission.

Kenneth F. Plumb,

Secretary.

[¶ 30,322]

46 F. R. 62439 (December 24, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Colorado-16); Order No. 197]

High-Cost Gas Produced From Tight Formations; Colorado

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Colorado Oil and Gas conservation Commission that the Sussex Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective December 16, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357-8307 or Walter Lawson, (202) 357-8556.

SUPPLEMENTARY INFORMATION:

Issued: December 16, 1981.

The Commission hereby amends § 271.703(d) of its regulations to include the Sussex Formation in Colorado as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by the Director, OPPR, issued September 4, 1981 (46 FR 45155, September 10, 1981) [1] based on a recommendation by the Colorado Oil and Gas Conservation Commission (Colorado) in accordance with § 271.703(c) that the Sussex Formation be designated as a tight formation.

Evidence submitted by Colorado supports the assertion that the Sussex Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Colorado recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and, therefore, incentive prices should be made available as soon as possible. The need to make incentive prices immediately available establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3342; Administrative Procedure Act, 5 U.S.C. 553)

In consideration of the foregoing, Part 271 of Subchapter H, Chapter I, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective December 16, 1981.

By the Commission.

Lois D. Cashell,
Acting Secretary.

[¶ 30,323]

46 F. R. 62439 (December 24, 1981)

18 CFR Part 271

[Docket No. RM79-76 (New Mexico-7; Order No. 198]

High-Cost Gas Produced From Tight Formations; New Mexico

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[1] Comments were invited and one comment supporting the recommendation was received. No party requested a hearing and no hearing was held.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final Rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the New Mexico Oil and Gas Conservation Division that the Pictured Cliffs Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective December 16, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8307 or Victor Zabel, (202) 357–8616.

SUPPLEMENTARY INFORMATION:

Issued: December 16, 1981.

The Commission hereby amends § 271.703(d) of its regulations to include the Pictured Cliffs Formation in New Mexico as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of proposed Rulemaking by the Director, OPPR, issued October 2, 1981 (46 FR 50065, October 9, 1981)[1] based on a recommendation by the new Mexico Oil Conservation Division (New Mexico) in accordance with § 271.703(c) that the Pictured Cliffs Formation be designated as a tight formation.

Evidence submitted by New Mexico supports the assertion that the Pictured Cliffs Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the New Mexico recommendation.

The amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and, therefore, incentive prices should be made available as soon as possible. The need to make incentive prices immediately available establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*; Natural Gas Policy Act of 1978, 15 U.S.C. 3101–3342; Administrative Procedure Act, 5 U.S.C. 553)

In consideration of the foregoing, Part 271 of Subchapter H, Chapter I, Title 18, *Code of Federal Regulations*, is amended as set forth below, effective December 16, 1981.

By the Commission.

Lois D. Cashell,
Acting Secretary.

[¶ 30,324]

46 F. R. 62440 (December 24, 1981)

18 CFR Part 271

[Docket No. RM79-76 (Texas-11); Order No. 199]

High-Cost Gas Produced From Tight Formations; Texas

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is authorized by section 107(c)(5) of the Natural Gas Policy Act of 1978 to designate certain types of natural gas as high-cost gas where the Commission determines that

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[1] Comments were invited and one comment supporting the recommendation was received. No party requested a hearing and no hearing was held.

the gas is produced under conditions which present extraordinary risks or costs. Under section 107(c)(5), the Commission issued a final regulation designating natural gas produced from tight formations as high-cost gas which may receive an incentive price (18 CFR 271.703). This rule established procedures for jurisdictional agencies to submit to the Commission recommendations of areas for designation as tight formations. This final order adopts the recommendation of the Railroad Commission of Texas that the Wilcox Formation be designated as a tight formation under § 271.703(d).

EFFECTIVE DATE: This rule is effective December 16, 1981.

FOR FURTHER INFORMATION CONTACT: Leslie Lawner, (202) 357–8307 or Walter Lawson, (202) 357–8556.

SUPPLEMENTARY INFORMATION:

Issued: December 16, 1981.

The Commission hereby amends § 271.703(d) of its regulations include the Wilcox Formation in Texas as a designated tight formation eligible for incentive pricing under § 271.703. The amendment was proposed in a Notice of Proposed Rulemaking by the Director, OPPR, issued July 24, 1981 (46 FR 38935, July 30, 1981)[1] based on a recommendation by the Railroad Commission of Texas (Texas) in accordance with § 271.703(c) that the Wilcox Formation be designated as a tight formation.

Evidence submitted by Texas supports the assertion that the Wilcox Formation meets the guidelines contained in § 271.703(c)(2). The Commission adopts the Texas recommendation.

This amendment shall become effective immediately. The Commission has found that the public interest dictates that new natural gas supplies be developed on an expedited basis, and, therefore, incentive price should be made available as soon as possible. The need to make incentive prices available immediately establishes good cause to waive the thirty-day publication period.

(Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.;* Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3342; Administrative Procedure Act, 5 U.S.C. 553)

In consideration of the foregoing, Part 271 of Subchapter H, Chapter I, Title 18, *Code of Federal Regulations,* is amended as set forth below, effective December 16, 1981.

By the Commission.

Lois D. Cashell,
Acting Secretary.

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[1] Comments were invited and one favorable comment was received. No party requested a public hearing and no hearing was held.